Iraqi Ministry personnel was also required to ensure they were kept informed about the status of projects, and they agreed with the proposed projects being planned.

Fossil Operations Manager–North America, Bechtel Power

2000–2003: Mr. Robinson was responsible for project execution of over half of the on-going North American power projects, including establishing the project management philosophy and procedures, continuously monitoring the project status including cost, schedule, safety, staffing, trends, change orders, and client relations. He provided real time feedback and guidance to the project managers about their performance, in addition to providing training and personal development. Mike assisted Business Development with project development and reviewed the commercial issues to ensure that they met business requirements.

Fossil Operations Manager–Europe, Africa, Middle East, Bechtel Power

1999–2000: In this capacity, Mr. Robinson was responsible for project execution of all power projects in the EAM region, including establishing project management philosophy and procedures. He continuously monitored project progress including cost, schedule, safety, client relations, staffing, and trends. Mike assisted with Business Development efforts and concurred with final estimates. He interfaced with other Regional Ops Managers to optimize resource usage and project execution.

Project Director, Dabhol Power Station Project

1994–1999: Bechtel and General Electric (GE) formed a consortium to perform the engineering, procurement, construction, and startup of this 2,240 MW combined cycle power project in India (at the time the largest foreign investment in India), with GE providing the major equipment and Bechtel providing the balance of the work. Mike had overall responsibility for the consortium, as well as being the prime interface with the Owners' Project Director. Primary activities included developing project execution philosophy, Bechtel/GE interface, and day-to-day direction to the project managers and site manager.

Manager of Projects, Fossil, Bechtel Power

1992–1994: Mr. Robinson was responsible for the overall management of numerous fossil projects in various stages of development and execution. He supervised project managers and assisted them in setting goals and establishing philosophy of approach to individual projects. Mike provided guidance to project managers in their day-to-day activities, including client relationship and providing formal and informal training and development of the project managers. He also coordinated interaction between projects in areas of business line goals, company direction, relevant project experience, resource sharing and allocation, and other pertinent information.

Project Manager, Coryton Cogeneration Power Project

1991–1992: Mr. Robinson was responsible for developing a lump sum package for the engineering, procurement, construction, and startup of a 500 MW combined cycle cogeneration plant for the Mobil Refinery in Coryton, England. Work included preliminary engineering to identify the technical scope of the project, selection and negotiation for lump sum contracts for the gas turbines, steam turbine, HRSG, and air-cooled condenser. Also included were development of a construction and labor relations' plan, project schedule, startup program, and full lump sum estimate. Assistance was provided to the client for permitting and non-recourse financing. Contractual negotiations for all terms and conditions were also included.

Project Manager, Panther Creek Project

1989–1991: Mr. Robinson assisted in project development including contract negotiations, cost, schedule, and testing requirements. He was responsible for project execution and management of engineering, construction, startup, procurement, and project controls. Mike coordinated and communicated with client/owner including change order negotiation and approval. He established terms and philosophy of job execution and kept appropriate management updated on project status. Mike also tracked job to final and successful completion.

Project Manager, Scrubgrass Project

1989–1989: Mr. Robinson assisted in project development including contract negotiations, cost, schedule, and testing requirements. He was responsible for project execution and management of engineering, construction, startup, procurement, and project controls. Mike coordinated and communicated with client/owner including charge order negotiation and approval. He established terms and philosophy of job execution and kept appropriate management updated on project status.

Project Superintendent, Gilberton Cogeneration Project

1986–1989: Mr. Robinson was the Project Superintendent for the construction of a $100 million cogeneration facility. Contract included power plant and coal handling facility — 40 percent was subcontracted. Mike supervised 30 nonmanual and 200 craftsmen.

Lead Contracts Coordinator, Scott Paper Cogeneration Project

1984–1986: Mr. Robinson's duties included front end planning and contract package scoping. He also supervised the contract coordination on a fluidized bed boiler.

Civil, Mechanical, and Electrical Craft Superintendent, Grand Gulf Nuclear Power Plant

1983–1984: Mr. Robinson's duties included front end planning and contract package scoping. He also supervised the contract coordination on a fluidized bed boiler.

Lead Civil Contracts Coordinator, Martin Marietta Coal Conversion

1981–1983: Mr. Robinson coordinated civil contracts, including contracts and specification interpretation, inspected and accepted the work, and negotiated extras and claims.

Various Civil Engineering and Quality Positions, Grand Gulf Nuclear Power Plant

1975–1981: Assignments at Grand Gulf included Assistant Lead Civil Engineer, Lead Area Engineer for the yard and control building, and Resident Civil Engineer. Mike acted on behalf of the Project Engineer at the jobsite. Duties as Lead Civil Quality Control Engineer and Assistant Project Field Quality Control Engineer included assisting in implementation of the project quality control policy and coordinating the work of all QC disciples. Later assignments included responsibility for senior contractors' changes, invoice approval, and monthly progress meetings. As HVAC Coordinator, Mike coordinated the completion of all heating and ventilating systems with the contractor and Bechtel. He supervised up to 100 people.

Construction Coordinator, SNUPPS

1972–1975: Mike reviewed drawings, specifications, project schedules, and procurement packages for final design phase and construction for the SNUPPS nuclear plant.

Civil Design Engineer, FFTF

1971–1972: Mike performed structural design and analysis for structural steel and concrete structures.

Civil Field Engineer, Calvert Cliffs Nuclear Power Plant

1969–1971: Mike was responsible for planning and scheduling, inspecting field placement, review drawings, quantity accounting, and scheduling civil activities.

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Stephen D. Routh

Project Manager (Engineering and Licensing)

Technical Qualifications

- Registered Professional Engineer, Virginia
- Six Sigma Champion

Education

- M.B.A., Finance, Mount St. Mary's College
- MEng., Nuclear Engineering, Pennsylvania State University
- B.S., Nuclear Engineering, Pennsylvania State University

Memberships

- Member, American Nuclear Society
- Member, ANS Large Light Water Reactor Consensus Committee
- Member, EPRI Advanced Nuclear Technology Group
- Member, NEI COL Task Force
- Member, NEI Seismic Issues Task Force

Steve Routh is a Senior Project Manager with over 35 years of nuclear experience and is currently the manager of Bechtel's Nuclear Engineering Services group. He has supported new nuclear generation efforts at various sites since 2001 and is recognized as an industry expert in nuclear engineering, safety, and licensing. Additionally, Steve is an active member of NEI and EPRI new generation task forces and working groups.

Manager, Nuclear Engineering Services

2009–Present: Mr. Routh is responsible for Bechtel's engineering and licensing services projects including support of operating plants, new nuclear generation, Fukushima response projects, and proposal preparation. He was previously the Project Manager for New Nuclear Generation Projects. Projects supported during this period include:

- North Anna Unit 3 Owner's Engineer and COL (APWR/ESBWR)
- Turkey Point COL (AP1000)
- Calvert Cliffs COL (U.S. EPR)
- South Texas COL (ABWR)
- V.C. Summer Units 2 & 3 Engineering and Licensing Support (AP1000)
- FENOC New Nuclear Site Selection Study (mPower)
- AREVA DCD (U.S. EPR)
- Clinch River Construction Permit Application (mPower)
- Dominion, South Texas, Watts Bar, and Constellation Fukushima response projects
- SONGS Spent Fuel Pool Island Cooling
- Vermont Yankee Decommissioning Cost Estimate
- Monticello and Prairie Island design modifications
- Fennovoima (Finland) New Plant Constructability and Schedule Assessment (EPR and ABWR)
- Wylfa Newydd (UK) New Plant Schedule and Cost Study (ABWR)

Additionally, Mr. Routh managed Bechtel's overall Fukushima response efforts including industry representation and development of approaches and capabilities, as well as responsibility for nuclear power proposal preparation.

Project Manager, Early Site Permit/Combined Operating License Technology Group

2001–2008: As Manager of the ESP/COL Technology Group, Mr. Routh provided engineering and licensing oversight of Bechtel's new generation projects (Calvert Cliffs, North Anna, South Texas, Vogtle, V.C. Summer, Turkey Point, and Victoria County). He was also the project manager for the North Anna ESP project, North Anna COL and Site Engineering project, and the Turkey Point COL project.

Manager of Regulatory Affairs, Nuclear Power

1999–2001: Mr. Routh was responsible for the licensing and regulatory oversight of the Bechtel nuclear power projects (new nuclear generation, steam generator replacements [SGRs], operating plant services) and SERCH, Bechtel's generic licensing service.

Licensing and Safety Analysis Supervisor, U. S. Enrichment Corporation

1995–1999: Mr. Routh managed the preparation of the upgraded Safety Analysis Reports for the Paducah and Portsmouth gaseous diffusion plants and managed activities for the project team including subcontractor support. He also provided detailed cost and schedule control, technical review of revised analyses; responded to NRC questions, and interfaced with NRC and DOE personnel. Mr. Routh also established regulatory processes for NRC oversight.

Project Engineer for the North Anna 1, North Anna 2, and Ginna Steam Generator Replacement Projects

1991–1995: Mr. Routh's duties included managing mechanical, materials, civil, nuclear, and licensing engineering activities in support of the projects including evaluation of alternative approaches, conceptual and detailed engineering, constructability reviews, subcontractor control, and client interface.

Assistant Chief Nuclear Engineer

1987–1991: Mr. Routh provided nuclear licensing support to operating plant services projects in the areas of design change packages operability and safety evaluations, justified continued operations, Part 21s, and NRC interaction, and assisted in the administration of the nuclear department and salary planning.

Nuclear/Licensing Supervisor

1983–1987: Mr. Routh prepared the safety analysis report, environmental report, and license documents for the Surry plant dry cask Independent spent fuel storage installation (the first licensed in the United States), and supported several other operating plant services and SGR projects.

Licensing Engineer/Deputy Supervisor, Grand Gulf Project

1980–1982: Mr. Routh supported the licensing effort for the operating license, preparation of the FSAR, environmental report, and the technical specifications. He supported NRC question responses, public hearings, as well as NRC safety evaluation report review and SER open item responses.

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Edward (Ed) A. Sherow

Engineering Manager

Technical Qualifications

- Six Sigma Champion

Education

- B.S., Electrical Engineering, Rensselaer Polytechnic Institute

Ed Sherow has over 43 years of engineering experience in the nuclear and fossil power industry, focusing on all phases of power plant activities, with specific background in electrical. He has worked on numerous projects throughout his career including Calvert Cliffs, Grand Gulf, Turkey Point, and Brown's Ferry Units 1 and 3 nuclear plants, as well as the design development of the U.S. EPR and the associated submittal of a COL for Calvert Cliffs Unit 3.

Engineering Manager, Nuclear Projects

2012–Present: Mr. Sherow is currently responsible for functional engineering management oversight, development, and execution of multiple nuclear projects. Work involves assistance and review of project estimates/schedules, project setup and staffing review, quality, schedule, and budget performance monitoring, project-specific process and procedural approvals, and coordination of lessons learned/experiences between multiple nuclear projects.

Nuclear Project Engineering Manager/Project Engineer, U.S. EPR Design Development & Certification and Calvert Cliffs Unit 3 COLA

2005–2011: Mr. Sherow managed the detailed design for the U.S. EPR, a 1,600 MW Generation III+ nuclear plant, with the first plant in the U.S. targeted for Calvert Cliffs. He also managed the work associated with supporting AREVA in achieving design certification. He also managed the development and support to UniStar (JV of EdF and Constellation) for submittal of the Combined Operating License Application for Calvert Cliffs Unit 3 based upon the EPR technology.

Fossil Project Engineer, Fossil Technology Group

2005–2005: Mr. Sherow managed the development and design of fossil generation plants. Work involved supervision or coordination of multidisciplinary engineers, technical specialists, estimators, and Business Development to provide proposals and the development aspects of fossil power projects. Close client coordination was required.

Task Integration Manager/Metrics Manager, Browns Ferry Unit 1 Restart Project

2003–2005: Mr. Sherow was responsible for the overall execution and quality of work relating to metrics reporting, integrated task equipment list programming/data integrity, and overall training program.

Assistant Project Manager/Project Engineer, Mountainview CCGT Project

2001–2003: As assistant project manager on this combined cycle gas project, Mr. Sherow's responsibilities included supervising execution planning, contract administration of the EPC Agreement, contract administration of major equipment (including the GE Power Island subcontract), contract compliance as well as the championing of other specific areas of critical concern to the success of the project. He was also responsible for interface with the Owner's project manager and for monitoring cost and schedule progress. As project engineer, he was also responsible for the overall engineering of the project, including technical correctness, compliance with codes, optimizing design/installation costs, and interface with suppliers and owner.

Fossil Project Engineer, Fossil Technology Group

1999–2001: Mr. Sherow managed the development and design of fossil generation plants. Work involved supervision or coordination of multidisciplinary engineers, technical specialists, estimators, and Business Development to provide proposals and the development aspects of fossil power projects. Close client coordination was required. During this period, Mr. Sherow also completed a 7-month assignment in 2000 at the Red Hills Generation Facility jobsite, a 440 MW CFB in Mississippi, as the Project Field Engineer responsible for all Field Engineering activities at the site.

Multi Project Acquisition Group (MPAG) Manager, MPAG

1996–1999: Mr. Sherow managed the electrical MPAG. The group is an integrated cross-functional team of engineering and procurement personnel implementing the Bechtel supply chain strategy. Efforts focused on optimizing and managing cost and schedule in the delivery of equipment. Key items included interfacing power projects and suppliers, implementing standard products, making process improvements and negotiating supplier agreements. During this period, he managed the combined Electrical/Control Systems MPAG until it was separated into two groups.

Project Manager, Substation/Transmission Engineering

1993–1996: In this assignment, Mr. Sherow was responsible for commercial and technical operations of the Gaithersburg Substation/Transmission Engineering (STE) Group. The STE Group varied in size from 20 to 30 multidiscipline engineers doing switchyard and transmission line work directly for utilities while also supporting Bechtel New Generation projects.

Project Engineer, Browns Ferry Nuclear Unit 3

1991–1993: Mr. Sherow's responsibilities included overseeing the electrical discipline consisting of 135 to 200 engineers preparing design modifications for upgrading Unit 3 to allow restart. Effort included monitoring schedules for all activities, monitoring costs, interfacing with client, supervising personnel, and preparing, evaluating, and approving proposals. He was also responsible for special projects and later the DCN Production Group. Special projects duties included overall responsibility for Procurement Engineering Group and engineering scheduling for restart of Browns Ferry Unit 3. For the DCN Production Group, he was responsible for multidiscipline group of 250 engineers preparing design modifications for upgrade of Unit 3 to allow restart. Effort included monitoring schedules for all activities, monitoring costs, interfacing with the client, and preparing, evaluating, and approving DCN modification packages.

Project Engineer/Group Supervisor, FPL Projects

1986–1991: Mr Sherow was responsible for managing FPL's drawing update efforts for Turkey Point Units 3 and 4. Work included approving drawings as client representative, monitoring and controlling work output, reviewing indicators, assigning work priorities for up to 60 people, and maintaining budgets/schedules. He was also responsible for managing the design fossil operating plant services and the electrical and I&C work.

Group Supervisor, Electrical/Control Systems Group, Operating Services

1984–1986: Mr. Sherow's tasks included supervising electrical and instrumentation and controls (I&C) work at various operating plants. He approved drawings, calculations and installation packages, preparing/evaluating proposals, coordinating with vendors/client, monitoring schedules/budgets, and electrical/control systems work of up to 20 engineers. Typical projects included addition of a precipitator for BG&E H.A. Wagner Unit 3, addition of dry cask spent fuel storage, radiation monitoring upgrade, and a facilities renovation for Virginia Power's North Anna and Surry Nuclear Stations, addition of natural gas warm-up for BG&E H.A. Wagner Unit 2, upgrading coal handling and sampling for Virginia Power's Mt. Storm Plant, a conversion to natural gas for FPL's Martin plants, and using coal water slurry as an alternate fuel for the Pfizer plant at Groton.

Group Supervisor, Electrical/Control Systems Group, Grand Gulf Units 1 and 2

1976–1984: In this assignment, Mr. Sherow's responsibilities included approving drawings, calculations, and installation packages, preparing/evaluating proposals, coordinating with vendors/client, monitoring schedules/budgets, and supervising electrical and I&C work.

Electrical Field Engineer, Calvert Cliffs Units 1 & 2 and Grand Gulf Unit 1

1972–1980: Mr. Sherow was responsible for overall installation and turnover to Startup of various plant systems. Duties included verifying system scope, walking down the system to ensure construction-reflected design, interfacing with Design Engineering, preparing punch lists for outstanding items, and releasing systems to Startup. He was also responsible for cable installation. Duties included verifying routing (both by drawing review and walkdowns), correcting routings, cable inspections, initiating termination installation, cable termination inspection, documentation reviews, and resolving problems.

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George D. Spindle

Construction Manager

Technical Qualifications

- Registered Civil Engineer, California and Pennsylvania (Retired)
- Member, National Society of Professional Engineers
- Member, California Society of Professional Engineers

Education

- B.S., Civil Engineering & Mathematics, University of Arizona
- Construction Executive Program, Texas A&M University

Over his 47 year Bechtel career, Mr. Spindle has served in a variety of construction management and leadership roles, both domestically and around the world. He offers broad and deep construction and managerial experience from nuclear and fossil power plants to oil and gas facilities with a variety of execution and contractual models. He has a proven ability to both manage and lead others in order to successfully execute projects on time and budget. Currently, Bechtel is privileged to have Mr. Spindle as a consultant resource, and he serves as a construction subject matter expert on a variety of Bechtel projects world-wide.

Consultant, Bechtel Group

2009–current: Since his retirement from Bechtel, Mr. Spindle has consulted on various Bechtel projects, providing insight on nuclear and fossil power, mining and metals, infrastructure, and oil and gas projects. His input has included analysis of execution strategies, risks, and implementation of lessons learned, as well as commercial and technical aspects of projects. He has also led two assessments of the status, challenges, and opportunities on the Watts Bar Unit 2 Completion Project.

Site Manager, Olympic Dam Project

2009: Mr. Spindle was the Site Manager of the Olympic Dam Project in Australia, a $12B uranium mine for BHP-Billiton awarded to Bechtel on an EPC basis. He led the development and execution planning for the project until it was cancelled due to the economic downturn.

Manager of Construction, Bechtel Oil, Gas & Chemicals (OG&C)

2005–2008: Mr. Spindle oversaw the construction execution and personnel deployment for all OG&C projects world-wide.

Manager of Construction, Bechtel Construction Operations Incorporated (BCOI)

2000–2005: Mr. Spindle was responsible for the world-wide execution of construction projects, deployment of construction personnel, and the effective implementation of processes and procedures.

Manager of Construction, Bechtel Construction Co. / Bechtel Builders Inc.

1994–2000: Mr. Spindle was responsible for the execution of all construction projects in the Asia Pacific region, deployment of construction personnel, and the effective implementation of processes and procedures.

Manager of Construction, Bechtel Construction Co.

1992–1993: Mr. Spindle was responsible for the execution of all construction projects in Western North America and the Asia Pacific region, deployment of construction personnel, and the effective implementation of processes and procedures.

Manager of Construction, San Francisco Regional Office

1990–1992: Mr. Spindle was responsible for the execution of all construction projects sponsored by the SF office, deployment of construction personnel, and the effective implementation of processes and procedures.

Construction Manager, Bechtel Construction, Inc.

1989–1990: Mr. Spindle was responsible for the construction execution of all direct hire power and petroleum projects.

Field Construction Manager, Basic American Foods American I Cogeneration Project

1988–1989: Mr. Spindle was responsible for the construction execution of this 120 MW California cogen project, which primarily uses natural gas to provide supply steam for vegetable drying and power to the electric grid.

Field Construction Manager, Gilroy Food Cogeneration Project

1986–1987: Mr. Spindle was responsible for the construction execution of this 115 MW California cogen project, which primarily uses natural gas to provide supply steam for food processing and power to the electric grid.

Field Construction Manager / Project Superintendent, Colstrip Units 3 & 4 Power Project

1979–1986: Mr. Spindle was responsible for the construction execution of two coal-fired units in Montana, producing 740 MW each. He began the project as Superintendent and in 1984 became the Field Construction Manager.

Lead Civil Superintendent, Limerick Nuclear Generating Station

1974–1979: Mr. Spindle was responsible for all civil work in the reactor buildings.

Assistant Superintendent, Jim Bridger Generating Station

1973–1974: Mr. Spindle was responsible for supervising all craft personnel involved in civil earthworks on these four coal-fired units in Wyoming, producing a total of 2,110 MW.

Senior Field Engineer/Construction Coordinator, Limerick Nuclear Generating Station

1971–1973: As Senior FE, Mr. Spindle was responsible for construction planning and scheduling, and as CC he was the construction liaison between the field work and engineering.

Field Engineer, Monticello Nuclear Power Plant

1968–1970: Mr. Spindle was responsible for the construction planning and scheduling.

Various Construction Roles

1961–1968: Mr. Spindle held various construction labor and planning/scheduling positions.

Appendix C

Bechtel Weekly Reports

Bechtel Weekly Report
V.C. Summer Units 2 &3 Completion Assessment
Week Ending August 28, 2015

- Members of the Bechtel team are scheduled to arrive onsite on Tuesday afternoon, September 8.

- On August 19, Bechtel provided a suggested agenda for the Wednesday, September 9, Consortium presentation at the site. A revised version of the agenda was received from WEC on August 25. Some additional suggested changes were provided by Bechtel on August 26.

- On August 24, a conference call was held with WEC to discuss Bechtel's document request list:

  - WEC described the status of identifying and obtaining approval to release copies of documents to Bechtel.

  - WEC described that a document room would be setup in the NOB where hard copies of certain documents would be placed.

  - Bechtel provided clarifications of several documents requested to WEC on August 26.

  - No new documents were received from SCANA or the Consortium during the week. The last documents received were posted in SCANA's electronic reading room on August 14.

- A CD of the Owner's P6 Integrated Project Schedule (IPS) was received on August 19. Since then, Bechtel has down loaded the schedule, identified the subprojects, and has begun manipulations of the schedule data. Based on initial reviews:

  - The IPS CD does not include all of the P6 schedule files (e.g., the WEC Engineering files are missing and the Milestones integration file was not provided). Without the Milestones file, schedule calculations cannot be performed.

  - It appears that there are as many as 60 mandatory constraints in the schedule data base that are precluding a true calculation of critical path negative float. The path that will have the largest impact appears to be through the shield building.

  - There appear to be minimal quantities loaded in the schedule. Quantities for the next 3 months are included, but it is not clear if they are complete. Quantities loaded in the schedule are needed to understand the impacts on installation sustained unit rates.

  - A preliminary manpower curve extracted from the schedule shows a peak of around 450,000 hours (2,200 craft) for a single month. This appears significantly low for a two unit construction effort.

  An initial discussion of the above schedule items was conducted with CB&I Project Controls personnel on August 26.

- Members of Bechtel's team continued their review of documents provided by SCANA and the Consortium.

- Began review of subproject schedules related to Construction. Also began review of subproject schedules containing Engineering, Licensing, Procurement/Subcontracts, and Quality Assurance activities.

- Prepared preliminary list of Construction discussion topics and questions in preparation for site mobilization and initial interviews.

Bechtel Weekly Report
V.C. Summer Units 2 &3 Completion Assessment
Week Ending August 28, 2015

- For Construction, Bechtel is interested in more information about the shield building. Bechtel's assessment will focus on panel fabrication, engineering tolerances, engineering changes, and installation sequencing. Installation of bulks is likely a near second critical path and will also be a focus area for the assessment.

- Information still needed from the Consortium for the Construction assessment includes:

  - Quantity curves
  - Unit rates
  - Manpower curves: non-manual and craft
  - Percent complete curves and method of calculation
  - Manpower loaded schedule
  - Equipment release dates
  - Module details, delivery schedules, and summary of all
  - Shield wall details and delivery and installation schedule

Bechtel Weekly Report
V.C. Summer Units 2 &3 Completion Assessment
Week Ending September 4, 2015

- Members of the Bechtel team are scheduled to arrive onsite on Tuesday afternoon, September 8.

- The Consortium presentation to the Bechtel team is scheduled for Wednesday, September 9. A final agenda was issued by WEC on September 7.

- Status of Bechtel's document request:

  - No new documents were received from the Consortium, SCANA, or Santee Cooper during the week. The last documents received were posted in SCANA's electronic reading room on August 14.

  - Members of Bechtel's team continued their review of documents that have been received to date.

  - In September 4 and 7 emails, WEC provided the following status of documents:

    <u>219 Total Items Requested</u>

    - 138 items previously issued electronically or via IPS disc.
    - 20 items have been marked as duplicates to other items on the list.
    - 3 items have been approved as software access – no documentation required.
    - 1 item needs clarification from Bechtel regarding Bingo sheets (10.19).
    - 57 remaining items required approval to release.

    <u>Remaining 57 Items</u>

    - 45 items have been approved and printed or made available for review. The reading room should be set up on Tuesday, September 8, for access by the Bechtel team.
    - 10 items have been approved and are part of the September 9 presentation and/or will be made available during follow-up deep dive sessions (difficult to produce copies of the information).
    - 1 item is approved but information is still being gathered regarding Construction Equipment plan (4.5).
    - 1 item will be discussed on September 9 - Engineering Manpower curves (10.13).

- A CD of the Owner's P6 Integrated Project Schedule (IPS) was received on August 19. Bechtel has down loaded the schedule, identified the subprojects, and is continuing to manipulate the schedule data. Bechtel's Project Controls, Construction, Engineering, Procurement, and Licensing personnel continued our review of the IPS information.

Bechtel Weekly Report
V.C. Summer Units 2 &3 Completion Assessment
Week Ending September 11, 2015

1. Work Activities Performed Last Week (September 8-11)

1.1 General

- The Bechtel Assessment team arrived on Tuesday, September 8, 2015 to begin the six-week, onsite assessment effort.
- WEC and CB&I Consortium members gave a full-day presentation to the Bechtel Assessment team on Wednesday, September 9, 2015. Copies of the presentation were placed in the Assessment Reading Room.
- The Bechtel Assessment team spent most of Thursday, September 10, and a large part of Friday, September 11, in training in order for the Bechtel team members to be granted a badge that will allow the Bechtel personnel unescorted access to the site. It is expected that the badges for unescorted access will be issued sometime during the week of September 14.
- On Friday morning, September 11, SCE&G provided a site tour of Units 2 & 3 and a majority of the lay down areas. All of the Bechtel team members on site took this tour.
- On Friday afternoon, members of the Bechtel Assessment team began to review the hard copy documents placed in the Reading Room.

2. Work Activities Planned This Week (September 14-18)

2.1 General

- Complete badging for Bechtel Assessment team members.
- Scheduled breakout meetings with WEC and CB&I personnel on Tuesday (September 15), Wednesday (September 16), and Thursday (September 17) from 1-4 pm to discuss:
    - Quantity Curves
    - Craft Staffing Curves
    - % Complete Curve
    - Schedule – Critical Paths
    - Quality Issues
    - Modules

  Follow-up meetings will be schedule as needed.

2.2 Project Management

- Carl Rau and Dick Miller have requested to have singular interviews with the following people on Wednesday, September 16: Steve Byrne, Jeff Archie (in Japan all week), Ron Jones, Alan Torres, Carlette Walker, and Carl Churchman.
- Continue review of documents in Reading Room.

2.3 Construction

- Perform direct observation of site activities:
    - Jobsite and area walk downs with senior construction personnel responsible for work areas.

Bechtel Weekly Report
V.C. Summer Units 2 &3 Completion Assessment
Week Ending September 11, 2015

- Review of on-site fabrication activities of modules.
- Review of indirects with responsible superintendent.
- Review of construction equipment with responsible superintendent.
- Overview of the safety program including the successes and challenges.
- Overview of the Quality Control program and activities.
- Overview of the Work Package process and Document Control.
- Review of constructability review program with responsible manager.
- Attend the following meetings:
  - POD – 9-10 am
  - Area Schedule Review – Thurs 1-3 pm
  - Module meeting with Customer – Tues 11-12 pm
  - OCC & Site laydown plan – Wed 12-1 pm
  - Safety meeting
  - Individual Area Schedule Review meetings.

• Review documents in reading room.

• Conduct internal discussions on comparisons of VCS against Bechtel historical information on unit rates, schedule durations, quantities, manpower, etc.

• Review welding activities, quantities, and manpower required.

2.4 Engineering and Licensing

• Continue review of documents in Reading Room.

• Participate in breakout meetings described in Item 2.1. Schedule follow-up meetings as needed.

• Attend CB&I/WEC Engineering Issues Meeting (0700).

• Meetings are being scheduled with WEC, CB&I, and SCE&G lead engineering personnel.

• Followup meeting scheduled with Brian McIntyre, WEC Licensing, at 8 am on Tuesday, September 15.

• Meeting with April Rice, SCE&G Licensing, is scheduled for Tuesday, September 15, at 4:30 pm.

2.5 Procurement

• Continue review of documents in Reading Room.

• Meetings are being scheduled with CB&I Procurement at the corporate level, followed by the site team.

• Meetings are being scheduled with Westinghouse's Procurement organization.

• Attend the following meetings:
  - POD – 9-10 am
  - Area Schedule Review – Thru 1-3 pm
  - Module meeting with Customer – Tues 11- 12 pm
  - OCC & Site laydown plan – Wed 12-1 pm

Bechtel Weekly Report
V.C. Summer Units 2 &3 Completion Assessment
Week Ending September 11, 2015

	• Participate in schedule reviews with Bechtel Team. • Module Plan – Determine focus of review and where potentially the Bechtel team needs to go.
2.6	**Project Controls** • Continue review of documents in Reading Room. • Participate in breakout meetings described in Item 2.1. Schedule follow-up meetings as needed. • Develop sustained rate comparison evaluation tables against Bechtel historical data. • Begin critical path evaluations. • Begin productivity evaluations against Bechtel historical projects.

Bechtel Weekly Report
V.C. Summer Units 2 &3 Completion Assessment
Week Ending September 18, 2015

1. Project Management

Activities Performed Last Week (September 14-18)

- Four (of the nine) Bechtel personnel on the assessment team completed in-processing and received their Unit 1 badges. Four others were notified that their training was complete so they could be badged when they were available.
- Carl Rau and Dick Miller completed interviews with Ron Jones (VP-New Nuclear Operations and Owner's Project Director), Alan Torres (General Manager-Nuclear Plant Construction), and Carl Churchman (Consortium Project Director).
- September 17 – Bechtel (Steve Routh and Dick Miller) were invited and attended the Monthly Project Status Meeting.
- September 18 – Attended Consortium POD meeting.

Activities Planned This Week (September 21-25)

- Work with Jason Brown of WEC to identify what remaining document requests will be filled this week. Documents provided after this week may be too late to be considered in the Bechtel assessment.
- Complete Unit 1 badging for remaining Bechtel team members.
- Obtain CB&I badges for Bechtel team members.
- Conduct interviews with Carlette Walker (SCE&G VP - Nuclear Financial Administration), Jeffrey Archie (SVP-SCANA and CNO-SCE&G), and Stephen Byrne (EVP-SCANA and COO-SCE&G & President-Generation).
- Attend various team and Consortium meetings.
- Tour site construction areas.

2. Construction

Activities Performed Last Week (September 14-18)

- Reviewed Reading Room material including contract, quantity and manpower curves, September 9 Consortium presentation package, module drawings, etc.
- September 16 - Met with Bill Wood and JJ White and had a general discussion of project including nonmanual staffing, manual skill level and difficulties recruiting skilled crafts, and laid out plans for our walkdowns and interviews.
- September 14 – Toured laydown with SCE&G.
- September 15 – Attended SCE&G module meeting.
- September 15 – Attended Consortium Engineering overview presentation.
- September 15 – Participated in Consortium Project Controls presentation on quantity curves, manpower, earned percent complete, and critical path.
- September 16, 17, 18 – Attended POD meetings.
- September 16 – Met with Consortium Procurement and discussed procurement issues including laydown and warehouse issues, pipe holds and changes, organization.
- September 16 – Participated in Consortium Quality review of project with Dave Jantosik.
- September 17 – Toured the Unit 2 Nuclear Island and discussed issues with Bob Johnson and Andrew Fleetwood.
- September 17 – Toured the Module Assembly Building operation with Bart Schaffer and staff.
- September 18 – Toured the Turbine Building area with Scotty Holland and discussed issues impacting work.
- September 18 – Met with Indirects Superintendent Terry Bolton and reviewed indirect program.

Bechtel Weekly Report
V.C. Summer Units 2 &3 Completion Assessment
Week Ending September 18, 2015

Activities Planned This Week (September 21-25)

- Review new material as it is posted to the Reading Room.
- Attend Plan of the Day meetings.
- Attend September 21 Safety meeting.
- Discuss welding program with Mark Pietre.
- Attend September 21 meeting with Consortium on modules.
- Attend September 23 meeting with Consortium on QC program, including a detailed review of what the civil QC inspector does when inspecting a slab for concrete placement.
- Review Document Control Program, specifically how drawings are given to craftsmen and revisions tracked in the field.
- Review Work Package Program.
- Review Constructability Program.
- Conduct further review of Unit 2 Nuclear Island.
- Perform detailed review of Unit 2 containment schedule.
- Conduct internal discussions on comparisons of VCS against Bechtel historical information on unit rates, schedule durations, quantities, manpower, etc.

3. Engineering and Licensing

Activities Performed Last Week (September 14-18)

- Reviewed electronic and Reading Room material including engineering and licensing procedures, licensing schedules, contract, September 9 Consortium presentation package, module drawings, etc.
- September 14 – Attended Consortium Licensing overview presentation.
- September 15 – Attended Consortium Engineering overview presentation.
- September 15 – Attended Consortium Project Controls presentation.
- September 15 – Met with April Rice of SCE&G to discuss general licensing issues and processes.
- September 16 – Attended Consortium Procurement presentation.
- September 16 – Participated in Consortium Quality review of project with Dave Jantosik.
- September 16, 17 – Attended POD meetings.
- Participated in internal schedule discussions on comparisons of VCS against Bechtel historical information.

Activities Planned This Week (September 21-25)

- Review new material as it is posted to the Reading Room.
- Attend POD meetings.
- Meet with Brad Stokes and other SCE&G Engineering personnel.
- Attend September 21 meeting with Consortium on modules.
- Attend September 22 meeting with CB&I Engineering.
- Schedule visits to CB&I-Charlotte and WEC-Cranbury.
- Meet with Consortium Engineering personnel to discuss piping re-design effort and electrical support design.
- Obtain and evaluate metrics on E&DCRs and N&Ds.
- Review schedules for LARs and ITAAC closure.
- Provide Engineering and Licensing schedule input to Bechtel Project Controls.

Bechtel Weekly Report
V.C. Summer Units 2 &3 Completion Assessment
Week Ending September 18, 2015

4. Procurement

Activities Performed Last Week (September 14-18)

- Reviewed electronic and Reading Room material.
- September 15, 17 – Attended POD meetings.
- September 16 – Participated in Consortium Quality review of project with Dave Jantosik.
- September 16 – Met with Consortium site and corporate Procurement management personnel.
- September 17 – Participated in walkdown of Unit 2 containment and adjacent area.
- September 17 – Attended Area Schedule Review meeting.

Activities Planned This Week (September 21-25)

- Continue review of documents in Reading Room as they are submitted.
- Conduct additional meetings with CB&I Site Procurement to discuss data and process.
- Conduct walkdown of site warehouses and laydown yards.
- Schedule further discussion with WEC Procurement.
- Attend POD meetings.
- Attend September 21 meeting with Consortium on modules.
- Discuss need for site visits to module fabricator(s) and schedule.

5. Project Controls

Activities Performed Last Week (September 14-18)

- Reviewed electronic and Reading Room material.
- Compared current planned construction sustained rates to Bechtel historicals.
- Developed Bechtel version Level 2 schedule with additional detail within the key critical areas.
- Prepared a high level schedule milestone comparisons chart.
- Prepared initial productivity analysis for internal team reviews
- September 15 – Attended Consortium Engineering overview presentation.
- September 15 – Attended Consortium Project Controls presentation.
- September 16 – Attended Consortium Procurement presentation.

Activities Planned This Week (September 21-25)

- Continue review of documents in Reading Room as they are submitted.
- Schedule meetings with meetings with Abney Smith Jr. and Michele Stephens.
- Continue critical path evaluations.
- Start schedule probability assessment within P6 through use of PAR software.
- Review and finalize sustained rate comparison tables.
- Finalize Bechtel version L2 schedule for analysis reference.
- Create first revised schedule duration evaluation which considers current productivity impacts projected into the future.
- Create copy of the P6 Construction file with all hard constraints removed for future variation analysis.

Bechtel Weekly Report
V.C. Summer Units 2 &3 Completion Assessment
Week Ending September 25, 2015

1. Project Management

Activities Performed Last Week (September 21-25)

- All Bechtel personnel are now badged.
- Carl Rau and Dick Miller conducted interviews with Steve Byrne (COO & SVP), Jeff Archie (CNO & SVP), and Carlette Walker (VP Nuclear Financial Administration).
- Attended various team and Consortium meetings.

Activities Planned This Week (September 28-October 2)

- Work with Jason Brown of WEC to obtain the remaining documents requested.
- Interview Santee Cooper personnel.
- Meet with Bechtel assessment team members to review initial observations and recommendations.
- Attend various team and Consortium meetings.
- Tour site construction areas.
- Prepare sections of Bechtel assessment report.

2. Construction

Activities Performed Last Week (September 21-25)

- Reviewed Reading Room material.
- September 21 – Attended weekly superintendent safety meeting.
- September 21 – Met with Consortium personnel to discuss modules status and issues with deliveries and engineering.
- September 21 – Met with SCE&G Quality Manager to discuss client audits of CB&I quality.
- September 22 – Toured inside containment.
- September 22 – Attended the daily C20 Auxiliary Building and Containment 2 superintendent/field engineer schedule meeting.
- September 23 – Toured the shield building.
- September 23 – Met with CB&I Quality Control Manager to discuss organization and responsibilities.
- September 23 – Met with Consortium personnel to review the containment vessel schedule.
- September 24 – Met with CB&I Strategic Planning and Mechanical/Electrical Work Manager to discuss his group’s efforts and review work package approach.
- September 24 – Met with Consortium Civil Work Package and Document Control personnel and reviewed the Annex Building civil work package and document control organization.
- September 24 – Met with Consortium project controls personnel to review the Unit 2 containment vessel schedule.
- September 25 – Attended the videoconference with WEC home office and site engineering personnel.

Activities Planned This Week (September 28-October 2)

- Review new material as it is posted to the Reading Room.
- Attend Plan of the Day meetings.
- Hold meeting with CB&I Electrical superintendent to better understand electrical packages.
- Hold meeting with Consortium Advanced Constructability Personnel to better understand Containment 2 civil work.

Bechtel Weekly Report
V.C. Summer Units 2 &3 Completion Assessment
Week Ending September 25, 2015

- Hold meeting with Consortium personnel to discuss electrical quantities and electrical support designs.
- Hold meeting with CB&I personnel to understand discipline superintendent roles.
- Attend September 28 follow-up meeting with WEC home office and site engineering personnel.
- Meet with Consortium Strategic Planning personnel to discuss work packages for piping and electrical on September 29.
- Meet with Consortium personnel to discuss startup plan, schedule, component test matrix, etc. on September 30.
- Perform detailed review of containment, auxiliary building, and turbine building schedules.
- Conduct internal discussions on comparisons of VC Summer against Bechtel historical information on unit rates, schedule durations, quantities, manpower, etc.
- Prepare sections of Bechtel assessment report.

3. Engineering and Licensing

<u>Activities Performed Last Week (September 21-25)</u>

- Reviewed new material as it is posted to the Reading Room.
- Attended POD meetings on September 22 and 24.
- September 21 – Attended meeting with Consortium on modules.
- September 22 – Attended meeting with CB&I Engineering.
- September 23 – Attended meeting on with Consortium on Strategic Planning.
- September 24 – Attended meeting on Work Package Development and Document Control.
- September 25 – Held videoconference with WEC Home Office (Cranberry, PA) and site engineering personnel to discuss to-go Engineering and engineering changes.
- Reviewed limited available metrics on E&DCRs and N&Ds.
- Provided Engineering and Licensing schedule input to Bechtel Project Controls.

<u>Activities Planned This Week (September 28-October 2)</u>

- Continue review of documents in Reading Room as they are submitted
- Attend September 29 and October 1 POD meetings (focus is engineering).
- Attend September 28 meeting with WEC Engineering to address to-go work (follow-up to September 25 videoconference).
- Attend September 30 meeting with Brad Stokes and other SCE&G Engineering personnel.
- Hold follow-up meeting with CB&I Engineering.
- Hold follow-up meeting with CB&I Licensing.
- Hold follow-up meeting with SCE&G Licensing.
- Meet with Consortium Engineering personnel to discuss piping re-design effort.
- Meet with Consortium personnel to discuss electrical quantities and electrical support design.
- Obtain and evaluate metrics on E&DCRs and N&Ds.
- Review schedules for LARs and ITAAC closure.
- Review representative ITAAC closure packages.
- Provide Engineering and Licensing schedule input to Bechtel Project Controls.
- Prepare sections of Bechtel assessment report.

Bechtel Weekly Report
V.C. Summer Units 2 &3 Completion Assessment
Week Ending September 25, 2015

4. Procurement

Activities Performed Last Week (September 21-25)

- Reviewed Reading Room material.
- Conducted meetings with CB&I Site Procurement to discuss data, process, and reports.
- Conducted walkdown of site warehouses and laydown yards.
- September 21 – Attended meeting with Consortium on modules.
- September 25 – Attended videoconference with WEC home office and site engineering.

Activities Planned This Week (September 28-October 2)

- Continue review of documents in Reading Room as they are submitted.
- Conduct meeting with CB&I Charlotte and Site Procurement personnel (Consortium to schedule).
- Attend September 28 follow-up meeting with WEC home office and site engineering personnel.
- Prepare sections of Bechtel assessment report.

5. Project Controls

Activities Performed Last Week (September 21-25)

- Reviewed Reading Room material.
- Completed the projects baseline version Level 2 schedule with additional detail within the key critical areas.
- Created first version of Bechtel revised schedule forecast.
- Created baseline bulk installation curves based upon current Consortium forecast.
- Downloaded and reviewed the engineering/procurement P6 milestones file.
- September 22 – Attended Consortium Containment schedule overview.
- September 24 – Attended Consortium Auxiliary Building and Turbine Building schedule overview.

Activities Planned This Week (September 28-October 2)

- Continue review of documents in Reading Room as they are submitted.
- Create revised Bechtel forecasted critical path for evaluation.
- Create Basis and Assumptions file for Bechtel forecasts.
- Create multiple forecasts based upon productivity analysis.
- Finalize Bechtel version of Level 2 schedule for analysis reference.
- Create revised bulk and manpower curves based upon Bechtel forecasts.
- Create Unit 3 Level 2 schedule.
- Create combined Unit 2 and 3 craft manpower curves.
- Prepare sections of Bechtel assessment report.

Bechtel Weekly Report
V.C. Summer Units 2 &3 Completion Assessment
Week Ending October 2, 2015

1. Project Management

Activities Performed Last Week (September 28-October 2)

- Continued with Interviews of Owner Personnel.
- Attended various schedule, work planning, and startup meetings with Consortium members.
- Continued data validation of transmitted project documents.
- Prepared observations and recommendations.
- Prepared sections of Bechtel assessment report.

Activities Planned This Week (October 5-9)

- Interview Santee Cooper personnel.
- Meet with Bechtel assessment team members to review initial observations and recommendations.
- Attend various team and Consortium meetings.
- Tour site construction areas.
- Prepare additional observations and recommendations.
- Continue to prepare sections of Bechtel assessment report.

2. Construction

Activities Performed Last Week (September 28-October 2)

- Reviewed Reading Room material.
- September 29 – Met with CB&I Strategic Planning Group to discuss work packaging.
- September 29 – Met with CB&I Electrical Field Superintendent to review extremely dense and complex electrical raceway and hangers in containment.
- September 29 – Met CB&I Advanced Constructability program to understand group responsibilities.
- September 30 – Observed Work Package distribution from the Document Control Center for Unit 2 Nuclear Island at start of shift.
- September 30 and October 1 – Met CB&I Startup personnel to review startup program and area and system turnovers from construction.
- October 1 – Met with CB&I Modules Procurement Manager to review program for module procurement.
- October 1 – Met with CB&I Shield Wall Manager to review erection of shield wall and roof.
- October 1 – Toured Unit 2 containment and auxiliary buildings and Unit 3 condenser assembly area.
- Conducted internal discussions on comparisons of VC Summer against Bechtel historical information on unit rates, schedule durations, quantities, manpower, etc
- Prepared observations and recommendations.
- Prepared sections of Bechtel assessment report.

Activities Planned This Week (October 5-9)

- Review new material as it is posted to the Reading Room.
- Attend Plan of the Day meetings.
- Attend Safety Meeting.
- Meet with CB&I Labor Relations to discuss recruitment and training of crafts.
- Meet with CB&I Welding Engineering to discuss welding program.
- Meet with CB&I Field Engineering to discuss work packaging.
- Conduct internal discussions on comparisons of VC Summer against Bechtel historical information on

Bechtel Weekly Report
V.C. Summer Units 2 &3 Completion Assessment
Week Ending October 2, 2015

unit rates, schedule durations, quantities, manpower, etc.
- Prepare additional observations and recommendations.
- Continue to prepare sections of Bechtel assessment report.

3. Engineering and Licensing

<u>Activities Performed Last Week (September 28-October 2)</u>

- Reviewed new material as it is posted to the Reading Room.
- September 28 – Conducted follow-up conference call with WEC Cranberry Engineering.
- September 29 – Attended meeting with CB&I Strategic Planning Group to discuss work packaging.
- September 29 – Attended meeting with CB&I Electrical Field Superintendent.
- September 29 – Attended meeting CB&I Advanced Constructability program.
- September 30 and October 1 – Attended meeting with CB&I Startup personnel to review startup program.
- September 30 – Met with Brad Stokes, SCE&G General Manager, Engineering Services.
- October 1 - Met with Consortium Project Controls to review WEC Engineering schedule.
- Provided Engineering and Licensing schedule input to Bechtel Project Controls.
- Prepared observations and recommendations.
- Prepared sections of Bechtel assessment report.

<u>Activities Planned This Week (October 5-9)</u>

- Continue review of documents in Reading Room as they are submitted.
- Perform follow-up interviews with Consortium and SCE&G personnel as needed.
- Evaluate metrics on E&DCRs and N&Ds.
- Review schedules for LARs and ITAAC closure.
- Review representative ITAAC closure packages.
- Provide Engineering and Licensing schedule input to Bechtel Project Controls.
- Prepare additional observations and recommendations.
- Continue to prepare sections of Bechtel assessment report.

4. Procurement

<u>Activities Performed Last Week (September 28-October 2)</u>

- Reviewed Reading Room material.
- September 29 – Conducted follow-up meetings with CB&I Site Procurement to discuss data and reports on field procurement activity.
- September 2 – Attended meeting with CB&I on work packages.
- September 30 – Attended meeting with CB&I 1X4 Procurement Manager.
- October 1 – Attended meeting with CB&I Modules Procurement Manager.
- Reviewed ROYG Procurement Report.
- October 1 – Met with WEC to discuss ROYG reports and requested different sorts of reports.
- Prepared observations and recommendations.
- Prepared sections of Bechtel assessment report.

Activities Planned This Week (October 5-9)

- Continue review of documents in Reading Room as they are submitted.
- Continue to analyze the ROYG report, interface with Project Controls on schedule.
- Hold follow-up meetings as required with CB&I & WEC Procurement.
- Prepare additional observations and recommendations.
- Continue to prepare sections of Bechtel assessment report.

5. Project Controls

Activities Performed Last Week (September 28-October 2)

- Reviewed Reading Room material.
- Created revised Bechtel forecasted Unit 2 critical path for evaluation.
- Created bases and assumptions file for Bechtel forecasts.
- Evaluated multiple forecasts based upon productivity analysis.
- Finalized Bechtel version of Level 2 schedule for analysis reference.
- Created revised bulk and manpower curves based upon Bechtel forecasts.
- Created Unit 3 Level 2 schedule.
- Created combined Unit 2 and 3 craft manpower curves.
- Conducted internal review of preliminary schedule package and incorporated comments.
- September 30 – Attended Consortium commodity installation and manpower curves review.
- October 1 – Attended WEC Engineering schedule review.
- Prepared initial observations and recommendations.
- Prepared sections of Bechtel assessment report.

Activities Planned This Week (October 5-9)

- Continue review of documents in Reading Room as they are submitted.
- Update bases and assumptions file for Bechtel forecasts for Unit 3.
- Finalize Bechtel version of Level 2 Unit 3 schedule.
- Analyze Unit 2 and 3 bulk curves for stagger between units.
- Finalize combined Unit 2 and 3 craft manpower curves.
- Continue to prepare sections of Bechtel assessment report.
- Finalize schedule package for internal management review.
- Prepare additional observations and recommendations.
- Continue to prepare sections of Bechtel assessment report.

Bechtel Weekly Report
V.C. Summer Units 2 &3 Completion Assessment
Week Ending October 9, 2015

1. Project Management

Activities Performed Last Week (October 5-9)

- October 9 – Met with CB&I Functional Operations Manager in Charlotte.
- Reviewed draft schedule, quantities, and sustained rates developed by Bechtel Project Controls.
- Prepared observations and recommendations.
- Prepared sections of Bechtel assessment report.

Activities Planned This Week (October 12-16)

- Interview Santee Cooper personnel.
- Finalize observations and recommendations.
- Finalize sections of Bechtel assessment report.
- Meet with Bechtel assessment team members to review draft report sections, observations and recommendations.
- Complete preparation of Bechtel draft report.

2. Construction

Activities Performed Last Week (October 5-9)

- Reviewed Reading Room material.
- October 7 – Attended Plan of the Day meeting.
- October 7 – Met with CB&I Lead Welding Engineer to discuss welding program.
- October 7 – Met with CB&I Human Resources Director to discuss non-manual turnover.
- October 7 – Met with CB&I Project Director to review some initial observations of construction effort.
- October 9 – Met with CB&I Industrial Relations Director to discuss recruiting of crafts.
- Conducted internal discussions on comparisons of VC Summer against Bechtel historical information on unit rates, schedule durations, quantities, manpower, etc.
- Prepared observations and recommendations.
- Prepared sections of Bechtel assessment report.

Activities Planned This Week (October 12-16)

- Review new material as it is posted to the Reading Room.
- Attend Plan of the Day meetings.
- Visit Craft Training trailer.
- Meet with CB&I Work Package planning personnel discuss work packaging, expected problems with electrical installations.
- Conduct internal discussions on comparisons of VC Summer against Bechtel historical information on unit rates, schedule durations, quantities, manpower, etc.
- Finalize observations and recommendations.
- Finalize sections of Bechtel assessment report.

Bechtel Weekly Report
V.C. Summer Units 2 &3 Completion Assessment
Week Ending October 9, 2015

3. Engineering and Licensing

<u>Activities Performed Last Week (October 5-9)</u>

- Reviewed new material as it is posted to the Reading Room.
- Provided Engineering and Licensing schedule input to Bechtel Project Controls.
- Prepared observations and recommendations.
- Prepared sections of Bechtel assessment report.

<u>Activities Planned This Week (October 12-16)</u>

- Continue review of documents in Reading Room as they are submitted.
- Perform follow-up interviews with Consortium and SCE&G personnel as needed.
- Finalize observations and recommendations.
- Finalize sections of Bechtel assessment report.

4. Procurement

<u>Activities Performed Last Week (October 5-9)</u>

- Reviewed Reading Room material.
- October 7 – Conducted follow-up meetings with CB&I Site Procurement to discuss data and reports on field procurement activity.
- Reviewed ROYG Procurement Report.
- October 7, 8, 9 – Met with WEC Deputy Project Manager to discuss ROYG reports and requested different sorts of the ROYG report.
- Prepared observations and recommendations.
- Prepared sections of Bechtel assessment report.

<u>Activities Planned This Week (October 12-16)</u>

- Finalize observations and recommendations.
- Finalize input to Bechtel assessment report.

5. Project Controls

<u>Activities Performed Last Week (October 5-9)</u>

- Reviewed Reading Room material.
- Developed internal schedule package for review.
- Updated bases and assumptions to include Unit 3 addition to Level 2 schedule.
- Finalized Bechtel version of Level 2 schedule for analysis reference including Unit 3 forecasts.
- Conducted internal “Team Meeting” review and incorporated comments into overall schedule package.
- Decided on the separation duration between Unit 2 and 3 completion dates.
- Finalized Units 2 and 3 manpower curves.
- Created Unit 2 percent complete curves based on Bechtel forecast.
- October 9 – Met with CB&I Functional Operations Manager in Charlotte.

Bechtel Weekly Report
V.C. Summer Units 2 &3 Completion Assessment
Week Ending October 9, 2015

- Created additional Observations and Recommendations.
- Prepared sections of Bechtel assessment report.

Activities Planned This Week (October 12-16)

- Continue to review documents in Reading Room as they are submitted.
- Finalize Bechtel version of Level 2 Unit 3 schedule.
- Finalize observations and recommendations.
- Finalize sections of Bechtel assessment report.

Bechtel Weekly Report
V.C. Summer Units 2 &3 Completion Assessment
Week Ending October 16, 2015

1. Project Management

Activities Performed Last Week (October 12-16)

- October 16 – Met with SCE&G CEO.
- Reviewed draft schedule, quantities, and sustained rates developed by Bechtel Project Controls.
- Prepared observations and recommendations.
- Prepared sections of Bechtel assessment report.
- Prepared presentation to SCE&G and Santee Cooper executive management.

Activities Planned This Week (October 19-23)

- October 22 – Presentation to SCE&G and Santee Cooper executive management.
- Finalize observations and recommendations.
- Finalize sections of Bechtel assessment report.

2. Construction

Activities Performed Last Week (October 12-16)

- October 13, 15 – Attended Plan of the Day meeting.
- October 13 – Met with CB&I work planning group to discuss electrical and pipe hanger installation challenges.
- October 13 – Met with CB&I training manager to discuss program and capabilities of the onsite training facility and staff.
- October 14 – Performed field walkdown.
- Conducted internal discussions on comparisons of VC Summer against Bechtel historical information on unit rates, schedule durations, quantities, manpower, etc.
- Prepared observations and recommendations.
- Prepared sections of Bechtel assessment report.
- Prepared input for presentation to SCE&G and Santee Cooper executive management.

Activities Planned This Week (October 19-23)

- Conduct internal discussions on comparisons of VC Summer against Bechtel historical information on unit rates, schedule durations, quantities, manpower, etc.
- Finalize observations and recommendations.
- Finalize sections of Bechtel assessment report.

3. Engineering and Licensing

Activities Performed Last Week (October 12-16)

- October 14 – Performed field walkdown.
- Reviewed new material posted to the Reading Room.
- Prepared observations and recommendations.
- Prepared sections of Bechtel assessment report.
- Prepared input for presentation to SCE&G and Santee Cooper executive management.

Bechtel Weekly Report
V.C. Summer Units 2 &3 Completion Assessment
Week Ending October 16, 2015

Activities Planned This Week (October 19-23)

- Finalize observations and recommendations.
- Finalize sections of Bechtel assessment report.

4. Procurement

Activities Performed Last Week (October 12-16)

- Prepared observations and recommendations.
- Prepared sections of Bechtel assessment report.
- Prepared input for presentation to SCE&G and Santee Cooper executive management.

Activities Planned This Week (October 19-23)

- Finalize observations and recommendations.
- Finalize input to Bechtel assessment report.

5. Project Controls

Activities Performed Last Week (October 12-16)

- Reviewed Reading Room material.
- Developed internal schedule package for review.
- Prepared observations and recommendations.
- Prepared sections of Bechtel assessment report.
- Prepared input for presentation to SCE&G and Santee Cooper executive management.

Activities Planned This Week (October 19-23)

- Finalize observations and recommendations.
- Finalize sections of Bechtel assessment report.

From: Wenick, George(gdwenick@smithcurrie.com)
To: LINDSAY, RONALD
CC: BYNUM, ALVIS J JR
BCC:
Subject: Bechtel's Preliminary Analysis
Sent: 11/12/2015 11:01:50 AM -0500 (EST)
Attachments:

***This is an EXTERNAL email. Please do not click on a link or open any attachments unless you are confident it is from a trusted source.

Ron,
My firm retained Bechtel Power Corporation ("Bechtel") to provide certain services under a Professional Services Agreement ("PSA") dated August 6, 2015 concerning the V.C. Summer project ("Project"). The purpose of Bechtel's work was to "assist SCH and Owners in better understanding the current status and potential challenges of the Project in anticipate of litigation and also to help ensure the Project is on the most cost efficient trajectory to completion." PSA Attachment A at 1. Bechtel agreed that all communications from Bechtel would be regarded as "confidential and made solely for the purpose of assisting SCH in giving legal advice to Owner." PSA at ¶ 3.
Bechtel recently advised that it was in the process of drafting a preliminary report of its findings and provided an oral preview of such findings. The primary focus of the oral preview was schedule and completion. As part of the preview, Bechtel explained its methodology for analyzing the Project schedule.
Bechtel admitted during the preview that did not base its analysis on the current project
schedule being used by the Consortium. It explained that the Consortium's schedule was too large and complex for Bechtel to understand in the limited time that Bechtel had to perform its analysis. Emphasizing that point, Bechtel stated that it was unable even to download an electronic version of the Consortium's schedule, because of the time it would take to download a schedule of that size.
Instead of relying on the Consortium's schedule, Bechtel prepared a simplified, high-level schedule. That simplified schedule was based on Bechtel's prior experience with projects of similar size and complexity, and adapted to the Project. This fact alone means that Bechtel's preliminary analysis is of limited use. We have no reason to believe that Bechtel's conclusions have equal or superior merit, when compared with the Consortium's conclusions, which reflect the Consortium's years of experience at the Project.
More important, Bechtel described its schedule as a "Level 2" schedule. That is a reference to a commonly used system for classifying project schedules, based on the amount of detail involved, with Level 0 being the least detailed and Level 4 being the most detailed. The American Association of Cost Engineering, known as AACE International, defines these levels, as follows:

> Level 0: This is the total project and in effect is a single bar spanning the project time from start to finish. Functionally there is very little practical application for a schedule that is only a single bar other than to represent an element of a project or program time line. Level zero schedules normally will include the project or program major milestones and bars indicating key scope.
> Level 1: This represents the schedule for the project by its major components. For example, a schedule for a process plant may be divided into process area, storage and handling area, services, site areas, and utilities. A Level 1 schedule is normally displayed as a Gantt or bar chart and may include key milestones. To differentiate between program and project schedules: a Level 1 of a program schedule, for example, would be a combination of Level 0 schedules for each component project This would give program schedules at least one more level than the most detailed project schedule that constitutes the overall program.
> Level 2: Each schedule component is further subdivided for Level 2. For example, utility systems are further subdivided into water, electrical, gas, storm drainage and sanitary systems, etc. In most cases Level 2 schedules can only be shown as a bar chart although key constraints may also be displayed. Milestones are normally included.
> Level 3: The first level that a meaningful critical path network can be displayed and the CPM schedule can

be used to monitor and manage (control) the overall project work. Level 3 is a good level for the overall project control schedule since it is neither too summarized nor too detailed.

Levels 4-X: The level of schedule subdivision continues to whatever is appropriate detail for the user. When operating at more detailed levels, the planners generally work with segments of the total schedule. Often the project "rolling schedule" includes a "look-ahead" period of time (30-180 days) and a "look-back" at recent completed work periods.

The most important point to understand about the above classification is that Level 3 is the "first level that a meaningful critical path network can be displayed and the CPM schedule can be used to monitor and manage (control) the overall project work." Based on Bechtel's statement that its schedule is Level 2, its schedule is insufficiently detailed to enable Bechtel to provide a meaningful critical path analysis for making projections about Project completion.

Having retained Bechtel to aid in preparation for anticipated litigation, I find Bechtel's current, preliminary analysis to be unusable for that purpose. This does not mean that Bechtel's personnel do not have the qualifications necessary to provide meaningful information. It simply means that the analysis is not sufficiently mature to provide meaningful insights into the schedule or the anticipated completion date. Preliminary conclusions often have this shortcoming.

Please tell me if you would like this information in a more formal letter or memo.

George

Reply to:
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Crosby, Michael

From: Crosby, Michael
Sent: Wednesday, October 14, 2015 1:12 PM
To: Carter, Lonnie
Cc: cwrau@bechtel.com
Subject: *** Confidential *** Bechtel Assessment (Preliminary - Bullet Notes)

Lonnie,

Carl has provided (you/me) preliminary bullet notes from the Assessment (see below) ... SCE&G has not seen this yet.

I do not see any real surprises ... the Bechtel projection on commercial operation dates is sobering.

****

Once a CEO meeting is scheduled ... Carl will work to schedule a sit-down meeting with Byrne & me ... and also a separate meeting with Jeff Archie's staff ... but he needs to get you and Kevin nailed down first.

Per Carl ... the CEO meeting is looking like the 22nd or 23rd ... Marty told me your schedule was better on the 23rd.

Thanks,
Michael

From: Rau, Carl [mailto:cwrau@Bechtel.com]
Sent: Tuesday, October 13, 2015 3:55 PM
To: Crosby, Michael
Subject: [EXTERNAL SENDER] Bechtel Assessment

Michael,

The attached is hot off the press, Preliminary Assessment, which will form the basis of our presentation to the execs. I did not include recommendations as they are still in development but will be part of the exec review.

Call with questions,

Carl

Scope of the Assessment

- Evaluate the status of the project to assess the Consortium's ability to complete the project on the forecasted schedule.
- Focus was not on cost.
- Team comprised of 10 senior managers from the following functional areas – Project Management, Construction, Project Controls, Engineering & Licensing, Procurement, and Startup.

Preliminary Findings

Project Management

- The project management approach used by the Consortium does not provide appropriate visibility and accuracy on project progress and performance.
- There is a lack of accountability in various departments in both the Owner's and Consortium's organizations.
- The Consortium's lack of project management integration (e.g., resolution of constructability issues) is a significant reason for the current construction installation issues and project schedule delays.
- The current hands-off approach taken by the Owners towards management of the Consortium does not allow for real-time, appropriate cost and schedule mitigation.
- The WEC-CB&I relationship is extremely poor caused to a large extent by commercial issues.
- The overall morale on the project is low.

Project Controls

- Our preliminary assessment of the project schedule is that the commercial operation dates will be extended:
  - Unit 2: 18-26 months beyond the current June 2019 commercial operation date.
  - Unit 3: 24-32 months beyond the current June 2020 commercial operation date.

  The probability range is approximately 50%-75%.
- The Consortium's forecasts for schedule durations, productivity, forecasted manpower peaks, and percent complete are unrealistic.
- The Owners do not have an appropriate project controls team to assess/validate Consortium reported progress and performance.

Construction

- Construction productivity is poor: Unit 2 is 2.3, Unit 3 is 1.6.
- Manual and non-manual sustained overtime is negatively affecting productivity.
- CB&I's work planning procedures are overly complex and inefficient, directly affecting craft productivity.
- Aging of the construction workforce is impacting productivity.
- The indirect to direct ratio is very high at 157% (typical mega nuclear project is 35-40%).
- Field non-manual turnover is high at 17.4% per annum.
- The current construction percent complete per month is only 0.5% versus plan of 1.3%.
- The workable backlog is significantly more than the current craft workforce.
- The project safety, housekeeping, and quality records are very good.

Engineering and Licensing

- Based on the team's observation of current civil work, the issued design is often not constructible (currently averaging over 600 changes per month). The complexity of the engineering design has resulted in a significant number of changes to make the design constructible.
- The construction planning and constructability review efforts are not far enough out in front of the construction effort to minimize impacts.

- Resolution of many Engineering and Design Coordination Reports (E&DCRs) is behind schedule. The E&DCR backlog is not decreasing.

- Engineering staffing remains extremely high for this stage of the project (around 800 total engineers for WEC and CB&I); however, the staffing is needed to complete the design and provide support to construction.

- There is significant engineering and licensing workload remaining for electrical design, I&C, post construction design completion, ITAAC closure, etc. Much of this remaining engineering will potentially impact construction.

- 119 license amendment requests (LARs) and 657 departures have been identified to date. This is a significant project workload that is well planned and scheduled and interactions with the NRC are good. Emergent issues potentially requiring NRC approval of LARs remain a significant project concern.

Procurement

- There is a significant disconnect between Construction need dates and procurement delivery dates. There are:
  - 457 open WEC and 2,907 open CB&I equipment deliveries.
  - 31 WEC and 28 CB&I POs to be placed.

- The amount of stored material onsite is significant creating the need for an extended storage and maintenance program. Inventory validation in the yard is only at 48% accuracy.

- The current min-max warehousing program is insufficient for the scale of the construction effort which is impacting productivity.

Startup

- The startup test program schedule is in the early stages of development.

- The current boundary identification package turnover rate appears to be overly aggressive and not consistent with the current construction completion schedule.

BEFORE

THE PUBLIC SERVICE COMMISSION OF

SOUTH CAROLINA

DOCKET NO. 2015-103-E - ORDER NO. 2015-661

SEPTEMBER 10, 2015

IN RE:	Petition of South Carolina Electric & Gas Company for Updates and Revisions to Schedules Related to the Construction of a Nuclear Base Load Generation Facility at Jenkinsville, South Carolina	)))))	TABLE OF CONTENTS

schedule mitigation alternatives with WEC/CB&I. The review lasted for several months. It resulted in SCE&G's determination in March of 2015 that the schedules attached to the Petition in this matter were the appropriate schedules for the project given the information currently available. Tr. at 219. SCE&G's witnesses, Mr. Byrne and Mr. Jones, testified to the fact that in their opinion the construction schedule presented here represents a reasonable and prudent schedule for completing the construction of the Units. Tr. at 220, 274, 556. ORS has similarly reviewed and evaluated the schedule and supports its adoption as the anticipated construction schedule for the Units under S.C. Code Ann. § 58-33-270(B) (Supp. 2014). Tr. at 699-701.

3. Conclusion as to the Updated Construction Schedule

SCE&G notes in its testimony that WEC/CB&I's ability to fulfill the schedule presented here depends on WEC/CB&I achieving significant improvements in labor productivity and in the successful mitigation of certain forward-looking critical path items like design finalization and shield building panel production. The ability of WEC/CB&I to achieve these productivity improvements and accomplish the required schedule mitigation is not guaranteed. It is true, as Mr. Byrne testified, that construction of the Units has proceeded to a point where many of the initial risks and challenges of new nuclear construction have been overcome. Tr. at 240-253. But, as Mr. Byrne also testified, substantial risks to the project and its schedule remain from a number of factors which are listed in his testimony. Tr. at 253-263. For that reason, the construction schedule presented here is dynamic and will likely change several times before the project is complete. Tr. at 275. Nevertheless, the evidence shows that this construction schedule, which is set forth on Order Exhibit No. 1, is a reasonable and prudent plan for completing construction of the Units given the information available at this time. It is therefore appropriate, as the Settlement Agreement provides, for the Commission to approve this schedule under S.C. Code Ann. § 58-33-270(E) as the updated schedule for construction of the Units as provided for in the BLRA.

Based on the evidence of record in this proceeding and under the terms of S.C. Code Ann. § 58-33-270(E), the Commission approves Order Exhibit No. 1 as the updated construction schedule for the project. Exhibit No. 1 to this Order shall be substituted for Hearing Exhibit 2, SAB-5 (“Exhibit E”), which was the approved construction schedule referred to on page 93 of Order No. 2009-104(A) and all subsequent versions of that schedule. Until further order of the Commission, Order Exhibit No. 1 shall serve as the anticipated construction schedule for the Units as contemplated by S.C. Code Ann. §§ 58-33-270(B) and 58-33-275(A) (Supp. 2014).

B. Update to BLRA Approved Cost Schedule

SCE&G also seeks to update the anticipated schedule of capital costs for the Units to reflect the new Revised, Fully-Integrated Construction Schedule and other changes that have occurred in the construction plan since 2012. The components of these cost updates fall into several principal categories, each of which is discussed separately below.

1. Updates to Anticipated EAC Cost

The largest component of the cost update before the Commission is the increase in the estimated at completion cost (“EAC Cost”) for the Units under the EPC Contract. Based on updated cost information provided by WEC/CB&I, SCE&G anticipates that the

BECHTEL MTG 10/22/15

TOM
CARL

BECHTEL: CRAIG ALBERT \ CARL RAU \ DICK MILLER \ JOHN ATWELL \ JASON WARD

SANTEE MAHON / MICHAEL CROSBY / MIKE BAXLEY / [illegible]

SCANA KBH / SAB / SBA / RON LINDSAY / (G. WENICK ON PHONE)

CA: EARLY CHALLENGES ON GETTING DATA; WE ARE A PROJ MGT COMPANY NOT A CONSULTING COMPANY

DM 17% [illegible] NON MANUAL, 6% CRAFT

CAL [illegible] WORKING TO GO DESIGN W/ CB&I

CBI CAN ONLY FIND 50% OF MATL IN LAYDOWN AREAS

OT TOO HIGH

JW LARGEST SKED HAS EVER SEEN 230,000 ITEMS

SUFFICIENT [illegible] CRAFT AVAIL UP TO 3700 PEAK (CB&I CURRENT PROJ ~3200) - CAN EFFICIENTLY FIT MORE ON SITE

PLENTY OF EQPT ON SITE

CAL WOULD HAVE TO GO MUCH DEEPER TO ACCURATELY PREDICT SKED PROBABILITIES

HAVE TO REDUCE ENGINEERING AS SOON AS POSSIBLE 800 TO 600 NEXT WEEK 400 FOLLOWING WEEK

CA 10M MANHOURS TO GO GIVEN NEW SKED PROBABILITIES (& 5 MTO [illegible]) ~ $2B

[illegible] PLAN [illegible]
LITTLE REAL EVAL TIME
[illegible] ON THEIR EXPERTISE / EXPERIENCE
REPORTED WHAT THEY SAID IN HANGAR MTG
[illegible] ON DOCS COULDN'T GET OR [illegible]
[illegible]
NO PART 52 RECOGNITION - NO FOCUS LICENSING
[illegible] OF OWN TEAM NOT SUPPORT [illegible]

COMBINED EFFORT SNC i.e. LOCATE ENG @ SITE

REF Z1 COMPLETE & 4 PLANNED BUT NOT PART 52 [illegible]

[illegible] PROGRAM

[illegible] PLAN E&O FRIENDLY

santee cooper®

Lonnie N. Carter
President and
Chief Executive Officer
(843) 761-7039
fax: (843) 761-7037
lncarter@santeecooper.com

October 29, 2015

Mr. Kevin B. Marsh
Chairman & CEO
SCANA Corporation
100 SCANA Parkway, Building D
Cayce, SC 29033

Dear Kevin,

The Santee Cooper team and I would like to thank you for your leadership over the past several weeks in helping us through the WEC negotiation. There were few times when we were not completely aligned on the issues, and I am proud that each team kept their eye on the ball and collectively managed to get the EPC Agreement in a much better position moving forward.

As you know, we still have significant work ahead of us to keep this new momentum moving in the right direction. WEC and Fluor have challenging work ahead of them to coordinate themselves and validate our schedule. Also, WEC particularly has the significant upcoming challenge to unravel the leftover CB&I commercial issues that reside at each of the critical path submodule fabrication shops.

An extremely important next step for us is to quickly get the Bechtel assessment in-house. Once in-house, our teams can evaluate the recommendations, prioritize the recommendations that we determine need addressing, and develop an action plan and schedule. At the conclusion of Bechtel's presentation last Thursday, I was concerned that some of our team saw the presentation as a Bechtel sales pitch. While no doubt Bechtel would like more business from us, much of what they had to say resonates with me. Based on what we know today, some voids exist in the Project. The AP1000 projects were WEC's first stab at delivering an EPC coordinated package. Accordingly, WEC depended on Stone & Webster to integrate the project, and for many reasons--including WEC's design deficit--the Consortium failed on delivery of the overall EPC project coordination. What Bechtel told us was, in the absence of WEC and Stone & Webster being able to provide true mega-project integration which includes properly managing themselves, some party (in this case the Owners) had to be in a position to recognize that deficiency and act upon it promptly.

We are at a key point in coming to terms with our future engagement and management of the Project. Whether we use Bechtel, another consultant, "owners' engineer," our own employees or some combination is a key decision before the Owners. Now is the best opportunity we will have to make that determination.

Mr. Kevin B. Marsh
October 29, 2015
Page Two

WEC will now depend on Fluor to provide construction management and most likely overall project integration services. We have a real need and opportunity to re-configure our current project management team, which will necessarily include the addition of outside EPC management professionals in some capacity, to position ourselves to better engage and recognize issues as they arise, and influence the process in real time going forward.

Kevin, again I want to personally thank you for your leadership on this project, including the recent WEC negotiations. Your sound judgment and focus have been key to our good progress. I would like to meet with you soon to discuss the Bechtel assessment and collectively plan a path forward for improved project management. As with the recent negotiations, I will make this a priority schedule item.

Sincerely,

Lonnie

Lonnie N. Carter

/hlm

10-K 1 a12312015-10k.htm 10-K

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, DC 20549

FORM 10-K

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the Fiscal Year Ended December 31, 2015

SCANA® POWER FOR LIVING®

Commission File Number	Registrant, State of Incorporation, Address and Telephone Number	I.R.S. Employer Identification No.
1-8809	**SCANA Corporation** (a South Carolina corporation)	
1-3375	**South Carolina Electric & Gas Company** (a South Carolina corporation) 100 SCANA Parkway, Cayce, South Carolina 29033 (803) 217-9000	

Securities registered pursuant to Section 12(b) of the Act:
SCANA Corporation: Common stock, without par value, registered on The New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act:
South Carolina Electric & Gas Company: Series A Nonvoting Preferred Shares

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.
SCANA Corporation ☒ South Carolina Electric & Gas Company ☒

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or 15(d) of the Act.
SCANA Corporation ☐ South Carolina Electric & Gas Company ☐

Indicate by check mark whether the registrant: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.
SCANA Corporation Yes ☒ No ☐ South Carolina Electric & Gas Company Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).
SCANA Corporation Yes ☒ No ☐ South Carolina Electric & Gas Company Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K.
SCANA Corporation ☒ South Carolina Electric & Gas Company ☒

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company (as defined in Exchange Act Rule 12b-2).

SCANA Corporation	Large accelerated filer ☒	Accelerated filer ☐	Non-accelerated filer ☐	Smaller reporting company ☐
South Carolina Electric & Gas Company	Large accelerated filer ☐	Accelerated filer ☐	Non-accelerated filer ☒	Smaller reporting company ☐

Indicate by check mark whether the registrant is a shell company (as defined in Exchange Act Rule 12b-2).
SCANA Corporation Yes ☐ No ☒ South Carolina Electric & Gas Company Yes ☐ No ☒

The aggregate market value of voting stock held by non-affiliates of SCANA Corporation was $7.2 billion at June 30, 2015, the last business day of the registrant's most recently completed second fiscal quarter, based on the closing price of $50.65 per share. South Carolina Electric & Gas Company is a wholly-owned subsidiary of SCANA Corporation and has no voting stock other than its common stock, all of which is held beneficially and of record by SCANA Corporation. A description of registrants' common stock follows:

Registrant	Description of Common Stock	Shares Outstanding at February 19, 2016
SCANA Corporation	Without Par Value	142,916,917
South Carolina Electric & Gas Company	Without Par Value	40,296,147

Documents incorporated by reference: Specified sections of SCANA Corporation's Proxy Statement, in connection with its 2016 Annual Meeting of Shareholders, are incorporated by reference in Part III hereof.

This combined Form 10-K is separately filed by SCANA Corporation and South Carolina Electric & Gas Company. Information contained herein relating to any individual registrant is filed by such registrant on its own behalf. Each registrant makes no representation as to information relating to the other company.

South Carolina Electric & Gas Company meets the conditions set forth in General Instruction I(1) (a) and (b) of Form 10-K and therefore is filing this Form with the reduced disclosure format allowed under General Instruction I(2).

TABLE OF CONTENTS

TABLE OF CONTENTS

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

Statements included in this Annual Report on Form 10-K which are not statements of historical fact are intended to be, and are hereby identified as, "forward-looking statements" for purposes of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. Forward-looking statements include, but are not limited to, statements concerning key earnings drivers, customer growth, environmental regulations and expenditures, leverage ratio, projections for pension fund contributions, financing activities, access to sources of capital, impacts of the adoption of new accounting rules and estimated construction and other expenditures. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "could," "should," "expects," "forecasts," "plans," "anticipates," "believes," "estimates," "projects," "predicts," "potential" or "continue" or the negative of these terms or other similar terminology. Readers are cautioned that any such forward-looking statements are not guarantees of future performance and involve a number of risks and uncertainties, and that actual results could differ materially from those indicated by such forward-looking statements. Important factors that could cause actual results to differ materially from those indicated by such forward-looking statements include, but are not limited to, the following:

(1) the information is of a preliminary nature and may be subject to further and/or continuing review and adjustment;

(2) legislative and regulatory actions, particularly changes in electric and gas services, rate regulation, regulations governing electric grid reliability and pipeline integrity, environmental regulations, and actions affecting the construction of new nuclear units;

(3) current and future litigation;

(4) changes in the economy, especially in areas served by subsidiaries of SCANA;

(5) the impact of competition from other energy suppliers, including competition from alternate fuels in industrial markets;

(6) the impact of conservation and demand side management efforts and/or technological advances on customer usage;

(7) the loss of sales to distributed generation, such as solar photovoltaic systems;

(8) growth opportunities for SCANA's regulated and other subsidiaries;

(9) the results of short- and long-term financing efforts, including prospects for obtaining access to capital markets and other sources of liquidity;

(10) the effects of weather, especially in areas where the generation and transmission facilities of SCANA and its subsidiaries (the Company) are located and in areas served by SCANA's subsidiaries;

(11) changes in SCANA's or its subsidiaries' accounting rules and accounting policies;

(12) payment and performance by counterparties and customers as contracted and when due;

(13) the results of efforts to license, site, construct and finance facilities for electric generation and transmission, including nuclear generating facilities;

(14) the results of efforts to operate the Company's electric and gas systems and assets in accordance with acceptable performance standards, including the impact of additional distributed generation and nuclear generation;

(15) maintaining creditworthy joint owners for SCE&G's new nuclear generation project;

(16) the ability of suppliers, both domestic and international, to timely provide the labor, secure processes, components, parts, tools, equipment and other supplies needed, at agreed upon quality and prices, for our construction program, operations and maintenance;

(17) the results of efforts to ensure the physical and cyber security of key assets and processes;

(18) the availability of fuels such as coal, natural gas and enriched uranium used to produce electricity; the availability of purchased power and natural gas for distribution; the level and volatility of future market prices for such fuels and purchased power; and the ability to recover the costs for such fuels and purchased power;

(19) the availability of skilled, licensed and experienced human resources to properly manage, operate, and grow the Company's businesses;

(20) labor disputes;

(21) performance of SCANA's pension plan assets;

(22) changes in and realization of taxes and tax credits, including production tax credits for new nuclear units;

(23) inflation or deflation;

(24) compliance with regulations;

(25) natural disasters and man-made mishaps that directly affect our operations or the regulations governing them; and

(26) the other risks and uncertainties described from time to time in the reports filed by SCANA or SCE&G with the SEC.

SCANA and SCE&G disclaim any obligation to update any forward-looking statements.

DEFINITIONS

Abbreviations used in this Form 10-K have the meanings set forth below unless the context requires otherwise:

DEFINITIONS

Abbreviations used in this Form 10-K have the meanings set forth below unless the context requires otherwise:

TERM	**MEANING**
AFC	Allowance for Funds Used During Construction
ANI	American Nuclear Insurers
AOCI	Accumulated Other Comprehensive Income
ARO	Asset Retirement Obligation
BACT	Best Available Control Technology
BLRA	Base Load Review Act
CAA	Clean Air Act, as amended
CAIR	Clean Air Interstate Rule
CB&I	Chicago Bridge & Iron Company N.V.
CCR	Coal Combustion Residuals
CEO	Chief Executive Officer
CFO	Chief Financial Officer
CFTC	Commodity Futures Trading Commission
CERCLA	Comprehensive Environmental Response, Compensation and Liability Act
CGT	Carolina Gas Transmission Corporation
COL	Combined Construction and Operating License
Company	SCANA, together with its consolidated subsidiaries
Consolidated SCE&G	SCE&G and its consolidated affiliates
Consortium	A consortium consisting of WEC and Stone and Webster
Court of Appeals	United States Court of Appeals for the District of Columbia
CSAPR	Cross-State Air Pollution Rule
CUT	Customer Usage Tracker (decoupling mechanism)
CWA	Clean Water Act
DCGT	Dominion Carolina Gas Transmission LLC
DER	Distributed Energy Resource
DHEC	South Carolina Department of Health and Environmental Control
Dodd-Frank	Dodd-Frank Wall Street Reform and Consumer Protection Act
DOE	United States Department of Energy
DOJ	United States Department of Justice
DOT	United States Department of Transportation
DSM Programs	Demand Side Management Programs
ELG Rule	Federal effluent limitation guidelines for steam electric generating units
Energy Marketing	The divisions of SEMI, excluding SCANA Energy
EPA	United States Environmental Protection Agency
EPC Contract	Engineering, Procurement and Construction Agreement dated May 23, 2008
eWNA	Pilot Electric WNA
FASB	Financial Accounting Standards Board
FERC	United States Federal Energy Regulatory Commission
Fuel Company	South Carolina Fuel Company, Inc.
GAAP	Accounting principles generally accepted in the United States of America
GENCO	South Carolina Generating Company, Inc.
GHG	Greenhouse Gas
GPSC	Georgia Public Service Commission
GWh	Gigawatt hour

IRS	United States Internal Revenue Service
KVA	Kilovolt ampere
kWh	Kilowatt-hour
Level 1	A fair value measurement using unadjusted quoted prices in active markets for identical assets or liabilities
Level 2	A fair value measurement using observable inputs other than those for Level 1, including quoted prices for similar (not identical) assets or liabilities or inputs that are derived from observable market data by correlation or other means
Level 3	A fair value measurement using unobservable inputs, including situations where there is little, if any, market activity for the asset or liability
LNG	Liquefied Natural Gas
LOC	Lines of Credit
LTECP	SCANA Long-Term Equity Compensation Plan
MATS	Mercury and Air Toxics Standards
MCF	Thousand Cubic Feet
MGP	Manufactured Gas Plant
MMBTU	Million British Thermal Units
MW or MWh	Megawatt or Megawatt-hour
NAAQS	National Ambient Air Quality Standard
NASDAQ	The NASDAQ Stock Market, Inc.
NCUC	North Carolina Utilities Commission
NEIL	Nuclear Electric Insurance Limited
NERC	North American Electric Reliability Corporation
New Units	Nuclear Units 2 and 3 under construction at Summer Station
NPDES	National Permit Discharge Elimination System
NRC	United States Nuclear Regulatory Commission
NSPS	New Source Performance Standards
NSR	New Source Review
Nuclear Waste Act	Nuclear Waste Policy Act of 1982
NYMEX	New York Mercantile Exchange
NYSE	The New York Stock Exchange
OCI	Other Comprehensive Income
October 2015 Amendment	Amendment, dated October 27, 2015, to the EPC Contract
ORS	South Carolina Office of Regulatory Staff
PGA	Purchased Gas Adjustment
PHMSA	United States Pipeline Hazardous Materials Safety Administration
Price-Anderson	Price-Anderson Indemnification Act
PSNC Energy	Public Service Company of North Carolina, Incorporated
RSA	Natural Gas Rate Stabilization Act
Santee Cooper	South Carolina Public Service Authority
SCANA	SCANA Corporation, the parent company
SCANA Energy	A division of SEMI which markets natural gas in Georgia
SCE&G	South Carolina Electric & Gas Company
SCI	SCANA Communications, Inc.
SCPSC	Public Service Commission of South Carolina
SEC	United States Securities and Exchange Commission
SEMI	SCANA Energy Marketing, Inc.
SERC	SERC Reliability Corporation
SIP	State Implementation Plan

Southern Natural	Southern Natural Gas Company
Spirit Communications	SCTG Communications, Inc. (a wholly-owned subsidiary of SCTG, LLC) d/b/a Spirit Communications
Stone & Webster	Prior to December 31, 2015, CB&I Stone & Webster, a subsidiary of Chicago Bridge & Iron Company N.V. Effective December 31, 2015, Stone & Webster, a subsidiary of WECTEC, LLC, a wholly-owned subsidiary of WEC
Summer Station	V.C. Summer Nuclear Station
Supreme Court	United States Supreme Court
Transco	Transcontinental Gas Pipeline Corporation
TSR	Total Shareholder Return
VACAR	Virginia-Carolinas Reliability Group
VIE	Variable Interest Entity
WEC	Westinghouse Electric Company LLC
Williams Station	A.M. Williams Generating Station, owned by GENCO
WNA	Weather Normalization Adjustment

PART I

ITEM 1. BUSINESS

INVESTOR INFORMATION

SCANA's and SCE&G's annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports filed with or furnished to the SEC are available free of charge through SCANA's internet website at *www.scana.com* (which is not intended as an active hyperlink; the information on SCANA's website is not a part of this report or any other report or document that SCANA or SCE&G files with or furnishes to the SEC) as soon as reasonably practicable after these reports are filed or furnished.

SCANA and SCE&G post information from time to time regarding developments relating to SCE&G's new nuclear project and other matters of interest to investors on SCANA's website. On SCANA's homepage, there is a yellow box containing links to the Nuclear Development and Other Investor Information sections of the website. The Nuclear Development section contains a yellow box with a link to project news and updates. The Other Investor Information section of the website contains a link to recent investor related information that cannot be found at other areas of the website. Some of the information that will be posted from time to time, including the quarterly reports that SCE&G submits to the SCPSC and the ORS in connection with the new nuclear project, may be deemed to be material information that has not otherwise become public. Investors, media and other interested persons are encouraged to review this information and can sign up, under the Investor Relations Section of the website, for an email alert when there is a new posting in the Nuclear Development and Other Investor Information yellow box.

CORPORATE STRUCTURE AND SEGMENTS OF BUSINESS

SCANA is a South Carolina corporation created in 1984 as a holding company. SCANA and its subsidiaries had full-time, permanent employees of 5,829 as of February 19, 2016 and 5,886 as of February 20, 2015. SCANA does not directly own or operate any significant physical properties, but it holds directly all of the capital stock of its subsidiaries except as described below, each of which is incorporated in South Carolina.

Regulated Utilities

SCE&G is engaged in the generation, transmission, distribution and sale of electricity to approximately 698,000 customers and the purchase, sale and transportation of natural gas to approximately 347,000 customers (each as of December 31, 2015). SCE&G's business experiences seasonal fluctuations, with generally higher sales of electricity during the summer and winter months because of air conditioning and heating requirements, and generally higher sales of natural gas during the winter months due to heating requirements. SCE&G's electric service territory extends into 24 counties covering nearly 16,000 square miles in the central, southern and southwestern portions of South Carolina. The service area for natural gas encompasses all or part of 35 counties in South Carolina and covers approximately 23,000 square miles. More than 3.4 million persons live in the counties where SCE&G conducts its business. Resale customers include municipalities, electric cooperatives, other investor-owned utilities, registered marketers and federal and state electric agencies. Predominant industries served by SCE&G include chemicals, educational services, paper products, food products, lumber and wood products, health services, textile manufacturing, rubber and miscellaneous plastic products, automotive and tire and fabricated metal products.

PART I

ITEM 1. BUSINESS

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SCANA is a South Carolina corporation created in 1984 as a holding company. SCANA and its subsidiaries had full-time, permanent employees of 5,829 as of February 19, 2016 and 5,886 as of February 20, 2015. SCANA does not directly own or operate any significant physical properties, but it holds directly all of the capital stock of its subsidiaries except as described below, each of which is incorporated in South Carolina.

Regulated Utilities

SCE&G is engaged in the generation, transmission, distribution and sale of electricity to approximately 698,000 customers and the purchase, sale and transportation of natural gas to approximately 347,000 customers (each as of December 31, 2015). SCE&G’s business experiences seasonal fluctuations, with generally higher sales of electricity during the summer and winter months because of air conditioning and heating requirements, and generally higher sales of natural gas during the winter months due to heating requirements. SCE&G’s electric service territory extends into 24 counties covering nearly 16,000 square miles in the central, southern and southwestern portions of South Carolina. The service area for natural gas encompasses all or part of 35 counties in South Carolina and covers approximately 23,000 square miles. More than 3.4 million persons live in the counties where SCE&G conducts its business. Resale customers include municipalities, electric cooperatives, other investor-owned utilities, registered marketers and federal and state electric agencies. Predominant industries served by SCE&G include chemicals, educational services, paper products, food products, lumber and wood products, health services, textile manufacturing, rubber and miscellaneous plastic products, automotive and tire and fabricated metal products.

GENCO owns Williams Station and sells electricity, pursuant to a FERC-approved tariff, solely to SCE&G under the terms of a power purchase agreement and related operating agreement. Fuel Company acquires, owns and provides financing for SCE&G's nuclear fuel, certain fossil fuels and emission allowances.

PSNC Energy purchases, sells and transports natural gas to approximately 534,000 residential, commercial and industrial customers (as of December 31, 2015). PSNC Energy serves 28 franchised counties covering approximately 12,000 square miles in North Carolina. The predominant industries served by PSNC Energy include educational services, food products, health services, automotive, chemicals, non-woven textiles, electrical generation and construction.

Nonregulated Businesses

SEMI markets natural gas in the southeast and provides energy-related services. SCANA Energy, a division of SEMI, sells natural gas to approximately 450,000 customers (as of December 31, 2015). Georgia’s deregulated natural gas market includes approximately 1.6 million customers.

SCANA Services, Inc. provides administrative and management services to SCANA's other subsidiaries.

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Disposals

CGT was sold to Dominion Resources, Inc. at the end of January 2015 and now operates as DCGT. SCI was sold to Spirit Communications in February 2015. In addition, SCANA owns two insignificant energy-related companies that are being liquidated.

For information with respect to major segments of business, see Management’s Discussion and Analysis of Financial Condition and Results of Operations for SCANA and SCE&G and Note 12 of the consolidated financial statements for SCANA and SCE&G. All such information is incorporated herein by reference.

COMPETITION

For a discussion of the impact of competition, see the Overview section of Management’s Discussion and Analysis of Financial Condition and Results of Operations for SCANA and SCE&G.

For a discussion of cash requirements for construction and nuclear fuel expenditures, contractual cash obligations, financing limits, financing transactions and other related information, see the Liquidity and Capital Resources section of Management’s Discussion and Analysis of Financial Condition and Results of Operations for SCANA and SCE&G.

ELECTRIC OPERATIONS

Electric Sales

SCE&G’s sales of electricity and margins earned from those sales by customer classification as percentages of electric revenues were as follows:

	Sales		**Margins**	
Customer Classification	**2014**	**2015**	**2014**	**2015**
Residential	45%	45%	50%	50%
Commercial	32%	33%	33%	33%
Industrial	18%	17%	14%	14%
Sales for resale	2%	2%	1%	1%
Other	3%	3%	2%	2%
Total	100%	100%	100%	100%

Sales for resale include sales to three municipalities and one electric cooperative. Short-term system sales and margins were not significant for either period presented.

During 2015 SCE&G experienced a net increase of approximately 10,000 electric customers (growth rate of 1.5%), increasing its total electric customers to approximately 698,000 at year end.

For the period 2016-2018, SCE&G projects total territorial kWh sales of electricity to increase 1.4% annually (assuming normal weather), total retail sales to grow 1.4% annually (assuming normal weather), total electric customer base to increase 1.6% annually and territorial peak load (summer, in MW) to increase 2.4% annually. SCE&G projects a retail kWh sales decrease of approximately 1.1% and customer growth of 1.7% from 2015 to 2016. SCE&G’s goal is to maintain a planning reserve margin of between 14% and 20%; however, weather and other factors affect territorial peak load and can cause actual generating capacity on any given day to fall below the reserve margin goal.

Electric Interconnections

SCE&G purchases all of the electric generation of GENCO’s Williams Station under a Unit Power Sales Agreement which has been approved by FERC. Williams Station has a net generating capacity (summer rating) of 605 MW.

SCE&G’s transmission system extends over a large part of the central, southern and southwestern portions of South Carolina. The system interconnects with Duke Energy Carolinas, LLC, Duke Energy Progress, LLC, Santee Cooper, Georgia

Power Company and the Southeastern Power Administration’s Clarks Hill (Thurmond) Project. SCE&G is a member of VACAR, one of several

Power Company and the Southeastern Power Administration's Clarks Hill (Thurmond) Project. SCE&G is a member of VACAR, one of several geographic divisions within the SERC. SERC is one of eight regional entities with delegated authority from NERC for the purpose of proposing and enforcing reliability standards approved by FERC. The regional entities and all members of NERC work to safeguard the reliability of the bulk power systems throughout North America.

Fuel Costs and Fuel Supply

The average cost of various fuels and the weighted average cost of all fuels (including oil) were as follows:

	Cost of Fuel Used		
	2013	2014	2015
Per MMBTU:			
Nuclear	$ 1.11	$ 1.01	$ 0.95
Coal	4.28	3.90	3.81
Natural Gas	4.63	5.19	3.26
All Fuels (weighted average)	3.53	3.62	3.01
Per Ton: Coal	104.63	96.74	95.69
Per MCF: Gas	4.69	5.30	3.35

The sources and percentages of total MWh generation by each category of fuel for the preceding three years and estimates for the next three years follow:

	% of Total MWh Generated					
	Actual			Estimated		
	2013	2014	2015	2016	2017	2018
Coal	45%	50%	39%	38%	40%	40%
Nuclear	24%	19%	20%	24%	21%	21%
Hydro	4%	3%	3%	3%	3%	3%
Natural Gas & Oil	26%	26%	36%	33%	34%	34%
Biomass/Solar	1%	2%	2%	2%	2%	2%
Total	100%	100%	100%	100%	100%	100%

For a listing of the Company's generating facilities, see the Electric Properties section within ITEM 2. PROPERTIES.

In 2015, coal was primarily obtained through long-term supply contracts with suppliers located in eastern Kentucky, Tennessee, Virginia, and West Virginia. These contracts provide for approximately 2.0 million tons annually. Sulfur restrictions on the contract coal range from 1.0% to 1.6%. These contracts expire at various times through 2018. Spot market purchases may occur when needed or when prices are believed to be favorable. The Company relies on unit trains and, in some cases, trucks and barges for coal deliveries.

SCANA and SCE&G believe that SCE&G's operations comply with all applicable regulations relating to the discharge of sulfur dioxide and nitrogen oxide. See additional discussion at Environmental Matters in Management's Discussion and Analysis of Financial Condition and Results of Operations for SCANA and SCE&G.

SCE&G, for itself and as agent for Santee Cooper, and Westinghouse are parties to a fuel alliance agreement and contracts for fuel fabrication and related services. Under these contracts, SCE&G supplies enriched product to Westinghouse and Westinghouse supplies nuclear fuel assemblies for Summer Station Unit 1 and will supply assemblies for the New Units. Westinghouse will be SCE&G's exclusive provider of such fuel assemblies on a cost-plus basis. The fuel assemblies to be delivered under the contracts are expected to supply the nuclear fuel requirements of Summer Station Unit 1 and the New Units through 2033. SCE&G is dependent upon Westinghouse for providing fuel assemblies for the new AP1000 reactors in the New Units in the current and anticipated future absence of other commercially viable sources.

In addition, SCE&G has contracts covering its nuclear fuel needs for uranium, conversion services and enrichment services. These contracts have varying expiration dates through 2024. SCE&G believes that it will be able to renew contracts as they expire or enter into similar contractual arrangements with other suppliers of nuclear fuel materials and services and that

sufficient capacity for nuclear fuel supplies and processing exists to preclude the impairment of normal operations of its nuclear generating units.

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SCE&G stores spent nuclear fuel in its on-site spent-fuel pool, and has constructed a dry cask storage facility to accommodate the spent fuel output for the life of Summer Station Unit 1. In addition, Summer Station Unit 1 has sufficient on-site storage capacity to permit storage of the entire reactor core in the event that complete unloading should become desirable or necessary. For information about the contract with the DOE regarding disposal of spent fuel, see the Environmental section of Note 10 to the consolidated financial statements of SCANA and SCE&G.

SCE&G also uses long-term power purchase agreements to ensure that adequate power supply resources are in place to meet load obligations and reserve requirements. As of December 31, 2015, SCE&G had such agreements in place for 325 MW of capacity.

GAS OPERATIONS

Gas Sales-Regulated

Regulated sales of natural gas by customer classification as a percent of total regulated gas revenues sold or transported were as follows:

	SCANA		SCE&G	
Customer Classification	**2014**	**2015**	**2014**	**2015**
Residential	54.9%	57.0%	44.1%	47.9%
Commercial	26.5%	26.8%	28.2%	28.0%
Industrial	12.4%	11.0%	24.6%	20.6%
Transportation Gas	6.2%	5.2%	3.1%	3.5%
Total	100.0%	100.0%	100.0%	100.0%

For the period 2016-2018, SCANA projects total consolidated sales of regulated natural gas in MMBTUs to increase 1.7% annually (excluding transportation and assuming normal weather). Annual projected increases over such period in MMBTU sales include residential of 2.6%, commercial of 1.2% and industrial of 0.8%.

For the period 2016-2018, SCE&G projects total consolidated sales of regulated natural gas in MMBTUs to increase 1.4% annually (excluding transportation and assuming normal weather). Annual projected increases over such period in MMBTU sales include residential of 2.6%, commercial of 0.8% and industrial of 1.1%.

For the period 2016-2018, each of SCANA's and SCE&G's total regulated natural gas customer base is projected to increase 2.6% annually. During 2015 SCANA recorded a net increase of approximately 22,000 regulated gas customers (growth rate of 2.6%), increasing its regulated gas customers to approximately 881,000. Of this increase, SCE&G recorded a net increase of approximately 9,000 gas customers (growth rate of 2.7%), increasing its total gas customers to approximately 347,000 (as of December 31, 2015).

Demand for gas changes primarily due to weather and the price relationship between gas and alternate fuels.

Gas Cost, Supply and Curtailment Plans

SCE&G purchases natural gas under contracts with producers and marketers in both the spot and long-term markets. The gas is delivered to South Carolina through firm transportation agreements with Southern Natural (expiring in 2018), Transco (expiring at various times through 2031) and DCGT (expiring at various times through 2030). The maximum daily volume of gas that SCE&G is entitled to transport under these contracts is 212,194 MMBTU from Southern Natural, 104,652 MMBTU from Transco and 449,727 MMBTU from DCGT. Additional natural gas volumes may be delivered to SCE&G's system as capacity is available through interruptible transportation.

The daily volume of gas that SEMI is entitled to transport under service agreements with DCGT (expiring in 2016, 2017 and 2023) on a firm basis is 83,704 MMBTU.

SCE&G purchased natural gas, including fixed transportation, at an average cost of $3.67 per MMBTU during 2015 and $5.48 per MMBTU during 2014.

SCE&G was allocated 5,502,600 MMBTU of natural gas storage capacity on the systems of Southern Natural and Transco. Approximately 4,558,600 MMBTU of gas were in storage on December 31, 2015. To meet the requirements of its high priority natural gas customers during periods of maximum demand, SCE&G supplements its supplies of natural gas with two LNG liquefaction storage facilities, one of which has liquefaction capability. The LNG plants are capable of storing the liquefied equivalent of 1,964,600 MMBTU of natural gas. Approximately

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PSNC Energy purchases natural gas under contracts with producers and marketers on a short-term basis at market based prices and on a long-term basis for reliability assurance at first of the month index prices plus a reservation charge in certain cases. Transco transports natural gas to North Carolina through transportation agreements with varying expiration dates through 2032. On a peak day, PSNC Energy is capable of receiving daily transportation volumes of natural gas under these contracts, utilizing firm contracts of 710,062 MMBTU from Transco.

PSNC Energy purchased natural gas, including fixed transportation, at an average cost of $4.12 per MMBTU during 2015 compared to $5.67 per MMBTU during 2014.

To meet the requirements of its high priority natural gas customers during periods of maximum demand, PSNC Energy supplements its supplies of natural gas with underground natural gas storage services and LNG peaking services. Underground natural gas storage service agreements with Dominion Transmission, Inc., Columbia Gas Transmission, Transco and Spectra Energy provide for storage capacity of approximately 13,000,000 MMBTU. Approximately 11,000,000 MMBTU of gas were in storage under these agreements at December 31, 2015. In addition, PSNC Energy’s LNG facility can store the liquefied equivalent of 1,000,000 MMBTU of natural gas with regasification capability of approximately 100,000 MMBTU per day. Approximately 900,000 MMBTU (liquefied equivalent) of gas were in storage at December 31, 2015. LNG storage service agreements with Transco, Cove Point LNG and Pine Needle LNG provide for 1,300,000 MMBTU (liquefied equivalent) of storage space. Approximately 1,300,000 MMBTU (liquefied equivalent) were in storage under these agreements at December 31, 2015.

SCANA and SCE&G believe that supplies under long-term contracts and supplies available for spot market purchase are adequate to meet existing customer demands and to accommodate growth.

Gas Marketing-Nonregulated

SEMI markets natural gas and provides energy-related services in the Southeast. In addition, SCANA Energy, a division of SEMI, markets natural gas to approximately 450,000 customers (as of December 31, 2015) in Georgia’s natural gas market. Georgia’s natural gas market includes approximately 1.6 million customers.

Risk Management

For a discussion of risk management policies and procedures, see Note 6 to the consolidated financial statements for SCANA and SCE&G.

REGULATION

Regulatory jurisdictions to which SCANA and its subsidiaries are subject are described in the Regulatory Matters section of Management's Discussion and Analysis of Financial Condition and Results of Operations for SCANA and SCE&G.

SCE&G has obtained FERC authority to issue short-term indebtedness and to assume liabilities as a guarantor(pursuant to Section 204 of the Federal Power Act). SCE&G may issue unsecured promissory notes, commercial paper and direct loans in amounts not to exceed $1.6 billion outstanding with maturity dates of one year or less, and may enter into guaranty agreements in favor of lenders, bankers, and dealers in commercial paper in amounts not to exceed $600 million. GENCO has obtained FERC authority to issue short-term indebtedness not to exceed $200 million outstanding with maturity dates of one year or less. The authority described herein will expire in October 2016.

SCE&G holds licenses under the Federal Power Act for each of its hydroelectric projects. The licenses expire as follows:

Project	**License Expiration**
Saluda (Lake Murray)	*
Fairfield Pumped Storage/Parr Shoals	2020
Stevens Creek	2025

Project	License Expiration
Saluda (Lake Murray)	*
Fairfield Pumped Storage/Parr Shoals	2020
Stevens Creek	2025
Neal Shoals	2036

* SCE&G operates the Saluda hydroelectric project under an annual license while its long-term re-licensing application is being reviewed by FERC.

At the termination of a license under the Federal Power Act, FERC may extend or issue a new license to the previous licensee, or may issue a license to another applicant, or the federal government may take over the related project. If the federal government takes over a project or if FERC issues a license to another applicant, the federal government or the new licensee, as the case may be, must pay the previous licensee an amount equal to its net investment in the project, not to exceed fair value, plus severance damages.

RATE MATTERS

For a discussion of the impact of various rate matters, see the Regulatory Matters section of Management's Discussion and Analysis of Financial Condition and Results of Operations for SCANA and SCE&G, and Note 2 to the consolidated financial statements for SCANA and SCE&G.

Fuel Cost Recovery Procedures

The SCPSC's fuel cost recovery procedure determines the fuel component in SCE&G's retail electric base rates annually based on projected fuel costs for the ensuing 12-month period, adjusted for any over-collection or under-collection from the preceding 12-month period. The statutory definition of fuel costs includes certain variable environmental costs, such as ammonia, lime, limestone and catalysts consumed in reducing or treating emissions. The definition also includes the cost of emission allowances used for sulfur dioxide, nitrogen oxide, mercury and particulates. In 2014, the South Carolina General Assembly amended the statutory definition of fuel cost thereby allowing electric utilities to recover avoided costs under the Public Utility Regulatory Policy Act of 1978. The South Carolina General Assembly further amended the fuel cost statute to allow for the recovery of costs incurred as a result of offering DER programs and net metering to its customers as a separate component of the overall fuel factor. SCE&G may request a formal proceeding concerning its fuel costs at any time.

Fuel cost recovery procedures related to the Company's natural gas operations along with related rate proceedings by the SCPSC and NCUC are described in Note 2 to the consolidated financial statements for SCANA and SCE&G.

ENVIRONMENTAL MATTERS

Federal and state authorities have imposed environmental regulations and standards relating primarily to air emissions, wastewater discharges and solid, toxic and hazardous waste management. Developments in these areas may require that equipment and facilities be modified, supplemented or replaced. The ultimate effect of any new or pending regulations or standards upon existing operations cannot be predicted. For a discussion of how these regulations and standards may impact SCANA and SCE&G (including capital expenditures necessitated thereby), see the Environmental Matters section of Management's Discussion and Analysis of Financial Condition and Results of Operations and Note 10 to the consolidated financial statements for SCANA and SCE&G.

OTHER MATTERS

Insurance coverage for SCE&G's nuclear units is described in Note 10 to the consolidated financial statements for SCANA and SCE&G.

ITEM 1A. RISK FACTORS

The risk factors that follow relate in each case to the Company, and where indicated the risk factors also relate to Consolidated SCE&G.

Commodity price changes, delays and other factors may affect the operating cost, capital expenditures and competitive positions of the Company's and Consolidated SCE&G's energy businesses, thereby adversely impacting results of operations, cash flows and financial condition.

Our energy businesses are sensitive to changes in coal, natural gas, uranium and other commodity prices (as well as their transportation

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Our energy businesses are sensitive to changes in coal, natural gas, uranium and other commodity prices (as well as their transportation costs) and availability. Any such changes could affect the prices these businesses charge, their operating costs and the competitive position of their products and services. Consolidated SCE&G is permitted to recover the prudently incurred cost of purchased power and fuel (including transportation) used in electric generation through retail customers' bills, but purchased power and fuel cost increases affect electric prices and therefore the competitive position of electricity against other energy sources. In addition, when natural gas prices are low enough relative to coal to require the dispatch of gas-fired electric generation ahead of coal-fired electric generation, higher inventories of coal, with related increased carrying costs, may result. This may adversely affect our results of operations, cash flows and financial condition.

In the case of regulated natural gas operations, costs prudently incurred for purchased gas and pipeline capacity may be recovered through retail customers' bills. However, in both our regulated and deregulated natural gas markets, increases in gas costs affect total retail prices and therefore the competitive position of gas relative to electricity and other forms of energy. Accordingly, customers able to do so may switch to alternate forms of energy and reduce their usage of gas from the Company and Consolidated SCE&G. Customers on a volumetric rate structure unable to switch to alternate fuels or suppliers may reduce their usage of gas from the Company and Consolidated SCE&G. A regulatory mechanism applies to residential and commercial customers at PSNC Energy to mitigate the earnings impact of an increase or decrease in gas usage.

Certain construction-related commodities, such as copper and aluminum used in our transmission and distribution lines and in our electrical equipment, and steel, concrete and rare earth elements, have experienced significant price fluctuations due to changes in worldwide demand. To operate our air emissions control equipment, we use significant quantities of ammonia, limestone and lime. With EPA-mandated industry-wide compliance requirements for air emissions controls, increased demand for these reagents, combined with the increased demand for low sulfur coal, may result in higher costs for coal and reagents used for compliance purposes.

The costs of large capital projects, such as the Company's and Consolidated SCE&G's construction for environmental compliance and its construction of the New Units and associated transmission, are significant and are subject to a number of risks and uncertainties that may adversely affect the cost, timing and completion of the projects.

The Company's and Consolidated SCE&G's businesses are capital intensive and require significant investments in energy generation and in other internal infrastructure projects, including projects for environmental compliance. For example, SCE&G and Santee Cooper have agreed to jointly own, contract the design and construction of, and operate the New Units, which will be two 1,250 MW (1,117 MW, net) nuclear units at SCE&G's Summer Station, in pursuit of which they have committed and are continuing to commit significant resources. In addition, construction of significant new transmission infrastructure is necessary to support the New Units and is under way as an integral part of the project. Achieving the intended benefits of any large construction project is subject to many uncertainties. For instance, the ability to adhere to established budgets and construction schedules may be affected by many variables, such as the regulatory, legal, training and construction processes associated with securing approvals, permits and licenses and necessary amendments to them within projected timeframes, the availability of labor and materials at estimated costs, the availability and cost of financing, and weather. There also may be contractor or supplier performance issues or adverse changes in their creditworthiness, unforeseen difficulties meeting critical regulatory requirements, contract disputes and litigation, and changes in key contractors or subcontractors. There may be unforeseen engineering problems or unanticipated changes in project design or scope. Our ability to complete construction projects (including new baseload generation) as well as our ability to maintain current operations at reasonable cost could be affected by the availability of key components or commodities, increases in the price of or the unavailability of labor, commodities or other materials, increases in lead times for components, adverse changes in applicable laws and regulations, new or enhanced environmental or regulatory requirements, supply chain failures (whether resulting from the foregoing or other factors), and disruptions in the transportation of components, commodities and fuels. Some of the foregoing issues have been experienced in the construction of the New Units. A discussion of certain of those matters can be found under New Nuclear Construction in Note 10 to the consolidated financial statements for SCANA and SCE&G.

Should the construction of the New Units adversely deviate from the schedules (by more than 18 months), estimates, and projections timely submitted to and approved by the SCPSC pursuant to the BLRA, the SCPSC could disallow the additional capital costs that result from the deviations to the extent that it is deemed that the Company's failure to anticipate or avoid the deviation, or to minimize the resulting expenses, was imprudent, considering the information available at the time. Depending upon the magnitude of any such disallowed capital costs, the Company could be moved to evaluate the prudency of continuation, adjustment to, or termination of the project.

Furthermore, jointly owned projects, such as the current construction of the New Units, are subject to the risk that one or more of the joint owners becomes either unable or unwilling to continue to fund project financial commitments, new joint owners cannot be secured at equivalent financial terms, or changes in the joint ownership make-up will increase project costs and/or delay the completion.

Furthermore, jointly owned projects, such as the current construction of the New Units, are subject to the risk that one or more of the joint owners becomes either unable or unwilling to continue to fund project financial commitments, new joint owners cannot be secured at equivalent financial terms, or changes in the joint ownership make-up will increase project costs and/or delay the completion.

To the extent that delays occur, costs become unrecoverable, or we otherwise become unable to effectively manage and complete our capital projects, our results of operations, cash flows and financial condition, as well as our qualifications for applicable governmental programs and benefits, such as production tax credits, may be adversely affected.

The use of derivative instruments could result in financial losses and liquidity constraints. The Company and Consolidated SCE&G do not fully hedge against financial market risks or price changes in commodities. This could result in increased costs, thereby resulting in lower margins and adversely affecting results of operations, cash flows and financial condition.

The Company and Consolidated SCE&G use derivative instruments, including futures, forwards, options and swaps, to manage our financial market risks. The Company also uses such derivative instruments to manage certain commodity (i.e., natural gas) market risk. We could be required to provide cash collateral or recognize financial losses on these contracts as a result of volatility in the market values of the underlying commodities and financial contracts or if a counterparty fails to perform under a contract.

The Company strives to manage commodity price exposure by establishing risk limits and entering into contracts to offset some of our positions (i.e., to hedge our exposure to demand and other changes in commodity prices). We do not hedge the entire exposure of our operations from commodity price volatility. To the extent we do not hedge against commodity price volatility or our hedges are not effective, results of operations, cash flows and financial condition may be diminished.

Changing and complex laws and regulations to which the Company and Consolidated SCE&G are subject could adversely affect revenues, increase costs, or curtail activities, thereby adversely impacting results of operations, cash flows and financial condition.

The Company and Consolidated SCE&G operate under the regulatory authority of the United States government and its various regulatory agencies, including the FERC, NRC, SEC, IRS, EPA, CFTC and PHMSA. In addition, the Company and Consolidated SCE&G are subject to regulation by the state governments of South Carolina, North Carolina and Georgia via regulatory agencies, state environmental commissions, and state employment commissions. Accordingly, the Company and Consolidated SCE&G must comply with extensive federal, state and local laws and regulations. Such governmental oversight and regulation broadly and materially affect the operation of our businesses. In addition to many other aspects of our businesses, these requirements impact the services mandated or offered to our customers, and the licensing, siting, construction and operation of facilities. They affect our management of safety, the reliability of our electric and natural gas systems, the physical and cyber security of key assets, customer conservation through DSM Programs, information security, the issuance of securities and borrowing of money, financial reporting, interactions among affiliates, the payment of dividends and employment programs and practices. Changes to governmental regulations are continual and potentially costly to effect compliance. Non-compliance with these requirements by third parties, such as our contractors, vendors and agents, may subject the Company and Consolidated SCE&G to operational risks and to liability. We cannot predict the future course of changes in this regulatory environment or the ultimate effect that this changing regulatory environment will have on the Company’s or Consolidated SCE&G’s businesses. Non-compliance with these laws and regulations could result in fines, litigation, loss of licenses or permits, mandated capital expenditures and other adverse business outcomes, as well as reputational damage, which could adversely affect the cash flows, results of operations, and financial condition of the Company and Consolidated SCE&G.

Furthermore, changes in or uncertainty in monetary, fiscal, or regulatory policies of the Federal government may adversely affect the debt and equity markets and the economic climate for the nation, region or particular industries, such as ours or those of our customers. The Company and Consolidated SCE&G could be adversely impacted by changes in tax policy, such as the loss of production tax credits related to the construction of the New Units.

The Company and Consolidated SCE&G are subject to extensive rate regulation which could adversely affect operations. Large capital projects, results of DSM Programs and/or increases in operating costs may lead to requests for regulatory relief, such as rate increases, which may be denied, in whole or part, by rate regulators. Rate increases may also result in reductions in customer usage of electricity or gas, legislative action and lawsuits.

SCE&G’s electric operations in South Carolina and the Company’s gas distribution operations in South Carolina and North Carolina are regulated by state utilities commissions. In addition, the construction of the New Units by SCE&G is subject to rate regulation by the SCPSC via the BLRA. Consolidated SCE&G’s generating facilities are subject to extensive regulation and oversight from the NRC and SCPSC. SCE&G's electric transmission system is subject to extensive regulations and oversight from the SCPSC, NERC and FERC. Implementing and maintaining compliance with the NERC's mandatory reliability standards, enforced by FERC, for bulk electric systems could result in higher operating costs and capital expenditures. Non-compliance with these standards could subject SCE&G to substantial monetary penalties. Our gas marketing operations in Georgia are subject to state regulatory oversight and, for a portion of its operations, to rate regulation. There can be no assurance that

SCE&G’s electric operations in South Carolina and the Company’s gas distribution operations in South Carolina and North Carolina are regulated by state utilities commissions. In addition, the construction of the New Units by SCE&G is subject to rate regulation by the SCPSC via the BLRA. Consolidated SCE&G’s generating facilities are subject to extensive regulation and oversight from the NRC and SCPSC. SCE&G's electric transmission system is subject to extensive regulations and oversight from the SCPSC, NERC and FERC. Implementing and maintaining compliance with the NERC's mandatory reliability standards, enforced by FERC, for bulk electric systems could result in higher operating costs and capital expenditures. Non-compliance with these standards could subject SCE&G to substantial monetary penalties. Our gas marketing operations in Georgia are subject to state regulatory oversight and, for a portion of its operations, to rate regulation. There can be no assurance that Georgia’s gas delivery regulatory framework will remain unchanged as market conditions evolve.

Furthermore, Dodd-Frank affects the use and reporting of derivative instruments. The regulations under this legislation provide for substantial additional regulation of over-the-counter and security-based derivative instruments, among other things, and require numerous rule-makings by the CFTC and the SEC to implement, many of which are still pending final action by those federal agencies. The Company and Consolidated SCE&G have determined that they meet the end-user exception to mandatory clearing of swaps under Dodd-Frank. In addition, the Company and Consolidated SCE&G have taken steps to ensure that they are not the party required to report these transactions in real-time (the "reporting party") by transacting solely with swap dealers and major swap participants, when possible, as well as entering into reporting party agreements with counterparties who also are not swap dealers or major swap participants, which establishes that those counterparties are obligated to report the transactions in accordance with applicable Dodd-Frank regulations. While these actions minimize the reporting obligations of the Company, they do not eliminate required recordkeeping for any Dodd-Frank regulated transactions. Moreover, the Company retains reporting responsibility for certain types of swaps, such as the annual reporting of trade options. Despite qualifying for the end-user exception to mandatory clearing and ensuring that neither the Company nor Consolidated SCE&G is the reporting party to a transaction required to be reported in real-time, we cannot predict when the final regulations will be issued or what requirements they will impose.

Although we believe that we have constructive relationships with the regulators, our ability to obtain rate treatment that will allow us to maintain reasonable rates of return is dependent upon regulatory determinations, and there can be no assurance that we will be able to implement rate adjustments when sought.

The Company and Consolidated SCE&G are subject to numerous environmental laws and regulations that require significant capital expenditures, can increase our costs of operations and may impact our business plans or expose us to environmental liabilities.

The Company and Consolidated SCE&G are subject to extensive federal, state and local environmental laws and regulations, including those relating to water quality and air emissions (such as reducing nitrogen oxide, sulfur dioxide, mercury and particulate matter). Some form of regulation is expected at the federal and state levels to impose regulatory requirements specifically directed at reducing GHG emissions from fossil fuel-fired electric generating units. On August 3, 2015, the EPA issued a revised standard for new power plants by re-proposing NSPS under the CAA for emissions of carbon dioxide from newly constructed fossil fuel-fired units. The final rule requires all new coal-fired power plants to meet a carbon emission rate of 1,400 pounds carbon dioxide per MWh. No new coal-fired plants could be constructed without partial carbon capture and sequestration capabilities. The Company is evaluating the final rule, but does not plan to construct new coal-fired units in the foreseeable future. In addition, on August 3, 2015, the EPA issued its final rule on emission guidelines for states to follow in developing plans to address GHG emissions from existing units. The rule includes state-specific goals for reducing national carbon dioxide emissions by 32% from 2005 levels by 2030. However, on February 9, 2016, the Supreme Court stayed the rule pending disposition of a petition of review of the rule in the Court of Appeals. Also, a number of bills have been introduced in Congress that seek to require GHG emissions reductions from fossil fuel-fired electric generation facilities, natural gas facilities and other sectors of the economy, although none have yet been enacted. In April 2012 the EPA issued the finalized MATS for power plants that requires reduced emissions from new and existing coal and oil-fired electric utility steam generating facilities. In October 2014, the stay on CSAPR was lifted and CAIR was set aside, thus reinstating CSAPR sulfur dioxide and nitrogen oxide allocations on electric generating units in 28 states, including South Carolina. In 2010, the EPA set a new NAAQS limit for sulfur dioxide and in August 2015 issued the Data Requirements Rule for implementing the one-hour sulfur dioxide standard. In October 2015 a new NAAQS limit for ozone was finalized by the EPA. The EPA's rule for cooling water intake structures to meet the best technology available became effective in October 2014, and the EPA also issued a final rule in December 2014 regarding the handling of coal ash and other combustion by-products produced by power plant operations. Furthermore, the EPA finalized new standards under the CWA governing effluent limitation guidelines for electric generating units in September 2015.

Compliance with these environmental laws and regulations requires us to commit significant resources toward environmental monitoring, installation of pollution control equipment, emissions fees and permitting at our facilities. These expenditures have been significant in the past and are expected to continue or even increase in the future. Changes in compliance requirements or more restrictive interpretations by governmental authorities of existing requirements may impose additional costs on us (such as the clean-up of MGP sites or additional emission allowances) or require us to incur additional expenditures or curtail some of our cost savings activities (such as the recycling of fly ash and other coal combustion products for beneficial use). Compliance with any GHG emission reduction requirements, including any mandated renewable portfolio standards, also may impose significant costs on us, and the resulting price increases to our customers may lower customer consumption. Such costs of compliance with environmental regulations could negatively impact our industry, our businesses and our results of operations and financial position, especially if emissions or discharge limits are reduced or more onerous permitting requirements or additional regulatory requirements are

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Renewable and/or alternative electric generation portfolio standards may be enacted at the federal or state level. In June 2014 the State of South Carolina enacted legislation known as Act 236 with the stated goal for each investor-owned utility to add up to 2% of its 5-year average retail peak demand with renewable electric generation resources by the end of 2020. A utility, at its option, may add an additional 1% during this period. Such renewable energy may not be readily available in our service territories and could be costly to build, acquire, and operate. Resulting increases in the price of electricity to recover the cost of these types of generation, as approved by regulatory commissions, could result in significantly lower usage of electricity by our customers. In addition, DER generation at customers' facilities could result in the loss of sales to those customers. Compliance with potential future portfolio standards could significantly impact our industry, our capital expenditures, and our results of operations and financial condition.

The compliance costs of these environmental laws and regulations are important considerations in the Company's and Consolidated SCE&G's strategic planning and, as a result, significantly affect the decisions to construct, operate, and retire facilities, including generating facilities. In effecting compliance with MATS, SCE&G has retired three of its oldest and smallest coal-fired units and converted three others such that they may be gas-fired.

The Company and Consolidated SCE&G are vulnerable to interest rate increases, which would increase our borrowing costs, and we may not have access to capital at favorable rates, if at all. Additionally, potential disruptions in the capital and credit markets may further adversely affect the availability and cost of short-term funds for liquidity requirements and our ability to meet long-term commitments; each could in turn adversely affect our results of operations, cash flows and financial condition.

The Company and Consolidated SCE&G rely on the capital markets, particularly for publicly offered debt and equity, as well as the banking and commercial paper markets, to meet our financial commitments and short-term liquidity needs if internal funds are not available from operations. Changes in interest rates affect the cost of borrowing. The Company's and Consolidated SCE&G's business plans, which include significant investments in energy generation and other internal infrastructure projects, reflect the expectation that we will have access to the capital markets on satisfactory terms to fund commitments. Moreover, the ability to maintain short-term liquidity by utilizing commercial paper programs is dependent upon maintaining satisfactory short-term debt ratings and the existence of a market for our commercial paper generally.

The Company's and Consolidated SCE&G's ability to draw on our respective bank revolving credit facilities is dependent on the ability of the banks that are parties to the facilities to meet their funding commitments and on our ability to timely renew such facilities. Those banks may not be able to meet their funding commitments to the Company or Consolidated SCE&G if they experience shortages of capital and liquidity or if they experience excessive volumes of borrowing requests from us and other borrowers within a short period of time. Longer-term disruptions in the capital and credit markets as a result of uncertainty, changing or increased regulation, reduced alternatives or failures of significant financial institutions could adversely affect our access to liquidity needed for our businesses. Any disruption could require the Company and Consolidated SCE&G to take measures to conserve cash until the markets stabilize or until alternative credit arrangements or other funding for our business needs can be arranged. Such measures could include deferring capital expenditures or other discretionary uses of cash. Disruptions in capital and credit markets also could result in higher interest rates on debt securities, limited or no access to the commercial paper market, increased costs associated with commercial paper borrowing or limitations on the maturities of commercial paper that can be sold (if at all), increased costs under bank credit facilities and reduced availability thereof, and increased costs for certain variable interest rate debt securities of the Company and Consolidated SCE&G.

Disruptions in the capital markets and its actual or perceived effects on particular businesses and the greater economy also adversely affect the value of the investments held within SCANA's pension trust. A significant long-term decline in the value of these investments may require us to make or increase contributions to the trust to meet future funding requirements. In

addition, a significant decline in the market value of the investments may adversely impact the Company's and Consolidated SCE&G's results of operations, cash flows and financial condition, including its shareholders' equity.

A downgrade in the credit rating of SCANA or any of SCANA's subsidiaries, including SCE&G, could negatively affect our ability to access capital and to operate our businesses, thereby adversely affecting results of operations, cash flows and financial condition.

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Various rating agencies currently rate SCANA's long-term senior unsecured debt, SCE&G's long-term senior secured debt, and the long-term senior unsecured debt of PSNC Energy as investment grade. In addition, rating agencies maintain ratings on the short-term debt of SCANA, SCE&G, Fuel Company (which ratings are based upon the guarantee of SCE&G) and PSNC Energy. Rating agencies consider qualitative and quantitative factors when assessing SCANA and its rated operating companies' credit ratings, including regulatory environment, capital structure and the ability to meet liquidity requirements. Changes in the regulatory environment or deterioration of our rated companies' commonly monitored financial credit metrics could adversely affect their debt ratings. If these rating agencies were to downgrade any of these ratings, particularly to below investment grade for long-term ratings, borrowing costs on new issuances would increase, which would diminish financial results, and the potential pool of investors and funding sources could decrease.

Operating results may be adversely affected by natural disasters, man-made mishaps and abnormal weather.

The Company has delivered less gas and received lower prices for natural gas in deregulated markets when weather conditions have been milder than normal, and as a consequence earned less income from those operations. During 2010 the SCPSC approved SCE&G's implementation of an eWNA on a pilot basis; it was discontinued at the end of 2013. Mild weather in the future could diminish the revenues and results of operations and harm the financial condition of the Company and Consolidated SCE&G. Hot or cold weather could result in higher bills for customers and result in higher write-offs of receivables and in a greater number of disconnections for non-payment. In addition, for the Company and Consolidated SCE&G, severe weather can be destructive, causing outages and property damage, adversely affecting operating expenses and revenues.

Natural disasters (such as electromagnetic events and the 2011 earthquake and tsunami in Japan) or man-made mishaps (such as the San Bruno, California natural gas transmission pipeline failure, the Kingston, Tennessee coal ash pond failure, and cyber-security failures experienced by many businesses) could have direct significant impacts on the Company and Consolidated SCE&G and on our key contractors and suppliers or could impact us through changes to federal, state or local policies, laws and regulations, and have a significant impact on our financial condition, operating expenses, and cash flows.

Potential competitive changes may adversely affect our gas and electricity businesses due to the loss of customers, reductions in revenues, or write-down of stranded assets.

The utility industry has been undergoing structural change for a number of years, resulting in increasing competitive pressures on electric and natural gas utility companies. Competition in wholesale power sales via a RTO/ISO (Regional Transmission Organization/Independent System Operator) is in effect across much of the country, but the Southeastern utilities have retained the traditional bundled, vertically integrated structure. Should a RTO/ISO-market be implemented in the Southeast, potential risks emerge from reliance on volatile wholesale market prices as well as increased costs associated with new delivery transmission and distribution infrastructure.

Some states have also mandated or encouraged unbundled retail competition. Should this occur in South Carolina, increased competition may create greater risks to the stability of utility earnings generally and may in the future reduce earnings from retail electric and natural gas sales. In a deregulated environment, formerly regulated utility companies that are not responsive to a competitive energy marketplace may suffer erosion in market share, revenues and profits as competitors gain access to their customers. In addition, the Company's and Consolidated SCE&G's generation assets would be exposed to considerable financial risk in a deregulated electric market. If market prices for electric generation do not produce adequate revenue streams and the enabling legislation or regulatory actions do not provide for recovery of the resulting stranded costs, a write-down in the value of the related assets would be required.

The Company and Consolidated SCE&G are subject to the risk of loss of sales due to the growth of distributed generation especially in the form of renewable power such as solar photovoltaic systems, which systems have undergone a rapid decline in their costs. As a result of federal and state subsidies, potential regulations allowing third-party retail sales, and advances in distributed generation technology, the growth of such distributed generation could be significant in the future. Such growth will lessen Company and Consolidated SCE&G sales and slow growth, potentially causing higher rates to customers.

The Company and SCE&G are subject to risks associated with changes in business and economic climate which could adversely affect revenues, results of operations, cash flows and financial condition and could limit access to capital.

Sales, sales growth and customer usage patterns are dependent upon the economic climate in the service territories of the Company and SCE&G, which may be affected by regional, national or even international economic factors. Some economic sectors important to our customer

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Sales, sales growth and customer usage patterns are dependent upon the economic climate in the service territories of the Company and SCE&G, which may be affected by regional, national or even international economic factors. Some economic sectors important to our customer base may be particularly affected. Adverse events, economic or otherwise, may also affect the operations of suppliers and key customers. Such events may result in the loss of suppliers or customers, in costs charged by suppliers, in changes to customer usage patterns and in the failure of customers to make timely payments to us. With respect to the Company, such events also could adversely impact the results of operations through the recording of a goodwill or other asset impairment. The success of local and state governments in attracting new industry to our service territories is important to our sales and growth in sales, as are stable levels of taxation (including property, income or other taxes) which may be affected by local, state, or federal budget deficits, adverse economic climates generally or legislative or regulatory actions. Budget cutbacks also adversely affect funding levels of federal and state support agencies and non-profit organizations that assist low income customers with bill payments.

In addition, conservation and demand side management efforts and/or technological advances may cause or enable customers to significantly reduce their usage of the Company's and SCE&G's products and adversely affect sales, sales growth, and customer usage patterns. For instance, improvements in energy storage technology, if realized, could have dramatic impacts on the viability of and growth in distributed generation.

Factors that generally could affect our ability to access capital include economic conditions and our capital structure. Much of our business is capital intensive, and achievement of our capital plan and long-term growth targets is dependent, at least in part, upon our ability to access capital at rates and on terms we determine to be attractive. If our ability to access capital becomes significantly constrained, our interest costs will likely increase and our financial condition and future results of operations could be significantly harmed.

Problems with operations could cause us to curtail or limit our ability to serve customers or cause us to incur substantial costs, thereby adversely impacting revenues, results of operations, cash flows and financial condition.

Critical processes or systems in the Company's or Consolidated SCE&G's operations could become impaired or fail from a variety of causes, such as equipment breakdown, transmission equipment failure, information systems failure or security breach, natural disasters, and the effects of a pandemic or terrorist attack on our workforce or facilities or on the ability of vendors and suppliers to maintain services key to our operations.

In particular, as the operator of power generation facilities, many of which entered service prior to 1985 and may be difficult to maintain, Consolidated SCE&G could incur problems, such as the breakdown or failure of power generation or emission control equipment, transmission equipment, or other equipment or processes which would result in performance below assumed levels of output or efficiency. The operation of the New Units or the integration of a significant amount of distributed generation into our systems may entail additional cycling of our coal-fired generation facilities and may thereby increase the number of unplanned outages at those facilities. In addition, any such breakdown or failure may result in Consolidated SCE&G purchasing emission allowances or replacement power at market rates, if such allowances and replacement power are available at all. These purchases are subject to state regulatory prudency reviews for recovery through rates. If replacement power is not available, such problems could result in interruptions of service (blackout or brownout conditions) in all or part of SCE&G's territory or elsewhere in the region. Similarly, a natural gas line failure of the Company or Consolidated SCE&G could affect the safety of the public, destroy property, and interrupt our ability to serve customers.

Events such as these could entail substantial repair costs, litigation, fines and penalties, and damage to reputation, each of which could have an adverse effect on the Company's revenues, results of operations, and financial condition. Insurance may not be available or adequate to respond to these events.

A failure of the Company to maintain the physical and cyber security of its operations may result in the failure of operations, damage to equipment, or loss of information, and could result in a significant adverse impact to the Company's financial condition, results of operations and cash flows.

The Company depends on maintaining the physical and cyber security of its operations and assets. As much of our business is part of the nation's critical infrastructure, the loss or impairment of the assets associated with that portion of our businesses could have serious adverse impacts on the customers and communities that we serve. Virtually all of the Company's operations are dependent in some manner upon our cyber systems, which encompass electric and gas operations, nuclear and

fossil fuel generating plants, human resource and customer systems and databases, information system networks, and systems containing confidential corporate information. Cyber systems, such as those of the Company, are often targets of malicious cyber attacks. A successful physical or cyber attack could lead to outages, failure of operations of all or portions of our businesses, damage to key components and equipment, fossil fuel generating plants, human resource and customer systems and databases, information system networks, and systems containing confidential corporate information. Cyber systems, such as those of the Company, are often targets of malicious cyber attacks. A successful physical or cyber attack could lead to outages, failure of operations of all or portions of our businesses, damage to key components and equipment, and exposure of confidential customer, employee, or corporate information. The Company may not be readily able to recover from such events. In addition, the failure to secure our operations from such physical and cyber events may cause us reputational damage. Litigation, penalties and claims from a number of parties, including customers, regulators and shareholders, may ensue. Insurance may not be adequate to respond to these events. As a result, the Company's financial condition, results of operations, and cash flows may be adversely affected.

SCANA’s ability to pay dividends and to make payments on SCANA’s debt securities may be limited by covenants in certain financial instruments and by the financial results and condition of its subsidiaries, thereby adversely impacting the valuation of our common stock and our access to capital.

We are a holding company that conducts substantially all of our operations through our subsidiaries. Our assets consist primarily of investments in subsidiaries. Therefore, our ability to meet our obligations for payment of interest and principal on outstanding debt and to pay dividends to shareholders and corporate expenses depends on the earnings, cash flows, financial condition and capital requirements of our subsidiaries, and the ability of our subsidiaries, principally Consolidated SCE&G, PSNC Energy and SEMI, to pay dividends or to repay funds to us. Our ability to pay dividends on our common stock may also be limited by existing or future covenants limiting the right of our subsidiaries to pay dividends on their common stock. Any significant reduction in our payment of dividends in the future may result in a decline in the value of our common stock. Such a decline in value could limit our ability to raise debt and equity capital.

A significant portion of Consolidated SCE&G’s generating capacity is derived from nuclear power, the use of which exposes us to regulatory, environmental and business risks. These risks could increase our costs or otherwise constrain our business, thereby adversely impacting our results of operations, cash flows and financial condition. These risks will increase as the New Units are developed.

In 2015, Summer Station Unit 1, operated by SCE&G, provided approximately 4.7 million MWh, or 20% of our generation. When the New Units are completed, our generating capacity and the percentage of total generating capacity represented by nuclear sources are expected to increase. Hence, SCE&G is subject to various risks of nuclear generation, which include the following:

- The potential harmful effects on the environment and human health resulting from a release of radioactive materials in connection with the operation of nuclear facilities and the storage, handling and disposal of radioactive materials;
- Limitations on the amounts and types of insurance commercially available to cover losses that might arise in connection with our nuclear operations or those of others in the United States;
- The possibility that new laws and regulations could be enacted that could adversely affect the liability structure that currently exists in the United States;
- Uncertainties with respect to procurement of nuclear fuel and the storage of spent nuclear fuel;
- Uncertainties with respect to contingencies if insurance coverage is inadequate; and
- Uncertainties with respect to the technological and financial aspects of decommissioning nuclear plants at the end of their operating lives.

The NRC has broad authority under federal law to impose licensing and safety-related requirements for the operation of nuclear generation facilities. In the event of non-compliance, the NRC has the authority to impose fines or shut down a unit, or both, depending upon its assessment of the severity of the situation, until compliance is achieved. Revised safety requirements promulgated by the NRC could necessitate capital expenditures at nuclear plants such as ours. Although we have no reason to anticipate a serious nuclear incident, a major incident at a nuclear facility anywhere in the world could cause the NRC to limit or prohibit the operation or licensing of any domestic nuclear unit, resulting in costly changes to units under construction or in operation and harming our results of operations, cash flows and financial condition. Furthermore, a major incident at a domestic nuclear facility could result in retrospective premium assessments under our nuclear insurance coverages. Finally, in today’s environment, there is a heightened risk of terrorist attack on the nation’s nuclear facilities, which has resulted in increased security costs at our nuclear plant.

Failure to retain and attract key personnel could adversely affect the Company’s and Consolidated SCE&G’s operations and financial performance.

As with many other utilities, a significant portion of our workforce will be eligible for retirement during the next few years. We must attract, retain and develop executive officers and other professional, technical and craft employees with the skills and experience necessary to successfully manage, operate and grow our businesses. Competition for these employees is high, and in some cases we must compete for these

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The Company and Consolidated SCE&G are subject to the risk that strategic decisions made by us either do not result in a return of or on invested capital or might negatively impact our competitive position, which can adversely impact our results of operations, cash flows, financial condition, and access to capital.

From time to time, the Company and Consolidated SCE&G make strategic decisions that may impact our direction with regard to business opportunities, the services and technologies offered to customers or that are used to serve customers, and the generating plants and other infrastructure that form the basis of much of our business. These strategic decisions may not result in a return of or on our invested capital, and the effects of these strategic decisions may have long-term implications that are not likely to be known to us in the short-term. Changing political climates and public attitudes, including customers' concerns regarding rate increases such as those periodic rate increases under the BLRA, may adversely affect the ongoing acceptability of strategic decisions that have been made (and, in some cases, previously supported by legislation or approved by regulators), to the detriment of the Company or Consolidated SCE&G (e.g., revision or repeal of the BLRA). Over time, these strategic decisions or changing attitudes toward such decisions, which could be adverse to the Company's or Consolidated SCE&G's interests, may have a negative effect on our results of operations, cash flows and financial condition, as well as limit our ability to access capital.

The Company and Consolidated SCE&G are subject to the reputational risks that may result from a failure to adhere to high standards of compliance with laws and regulations, ethical conduct, operational effectiveness, customer service and the safety of employees, customers and the public. These risks could adversely affect the valuation of our common stock and the Company's and Consolidated SCE&G's access to capital.

The Company and Consolidated SCE&G are committed to comply with all laws and regulations, to focus on the safety of employees, customers and the public, to maintain the privacy of information related to our customers and employees and to maintain effective communications with the public and key stakeholder groups, particularly during emergencies and times of crisis. Traditional news media and social media can very rapidly convey information, whether factual or not, to large numbers of people, including customers, investors, regulators, legislators and other stakeholders, and the failure to effectively manage timely communication through these channels could adversely impact our reputation. The Company and Consolidated SCE&G also are committed to operational excellence, to quality customer service, and, through our Code of Conduct and Ethics, to maintain high standards of ethical conduct in our business operations. A failure to meet these commitments may subject the Company and Consolidated SCE&G not only to fraud, regulatory action, litigation and financial loss, but also to reputational risk that could adversely affect the valuation of SCANA's stock, adversely affect the Company's and Consolidated SCE&G's access to capital, and result in further regulatory oversight. Insurance may not be available or adequate to respond to these events.

ITEM 1B. UNRESOLVED STAFF COMMENTS

Not Applicable

ITEM 2. PROPERTIES

SCANA owns no significant property other than the capital stock of each of its subsidiaries. It holds, directly or indirectly, all of the capital stock of each of its subsidiaries. See also Note 13 to the consolidated financial statements of SCANA.

SCE&G's bond indenture, which secures its First Mortgage Bonds, constitutes a direct mortgage lien on substantially all of its electric utility property. GENCO's Williams Station is also subject to a first mortgage lien which secures certain outstanding debt of GENCO.

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Electric Properties

The following table shows the electric generating facilities and their net generating capacity as of December 31, 2015.

	In-Service Date	Net Generating Capacity Summer (MW)	
Coal-Fired Steam:			
Wateree - Eastover, SC	1970	684	
Williams - Goose Creek, SC	1973	605	
Cope - Cope, SC	1996	415	
Kapstone - Charleston, SC	1999	85	
Gas-Fired Steam:			
McMeekin - Irmo, SC	1958	250	*
Urquhart Unit 3 - Beech Island, SC	1953	95	
Nuclear:			
Summer Station Unit 1 - Parr, SC (reflects SCE&G's 66.7% ownership share)	1984	647	
Summer Station Unit 2 and Unit 3 - Parr, SC			**
Internal Combustion Turbines:			
Peaking units - various locations in SC	1968-2010	349	
Urquhart Combined Cycle - Beech Island, SC	2002	458	
Jasper Combined Cycle - Jasper, SC	2004	852	
Hydro:			
Saluda - Irmo, SC	1930	200	
Other hydro units - various locations in or bordering SC	1905-1914	18	
Fairfield Pumped Storage - Parr, SC	1978	576	

* McMeekin units were fueled with coal and natural gas during 2015. The Company expects to burn natural gas exclusively beginning in early 2016.
** SCE&G owns 55% of Unit 2 and Unit 3, which are being constructed at Summer Station.

SCE&G owns 435 substations having an aggregate transformer capacity of 31.0 million KVA. The transmission system consists of 3,450 miles of lines, and the distribution system consists of 18,478 pole miles of overhead lines and 7,264 trench miles of underground lines.

Natural Gas Distribution and Transmission Properties

SCE&G's natural gas system includes 447 miles of transmission pipeline of up to 20 inches in diameter that connect its distribution system with Southern Natural, Transco and DCGT. SCE&G’s distribution system consists of 17,046 miles of distribution mains and related service facilities. SCE&G also owns two LNG plants, one located near Charleston, South Carolina, and the other in Salley, South Carolina. The Charleston facility can liquefy up to 6,180 MMBTU per day and store the liquefied equivalent of 1,009,400 MMBTU of natural gas. The Salley facility can store the liquefied equivalent of 927,000 MMBTU of natural gas and has no liquefying capabilities. The LNG facilities have the capacity to regasify approximately 61,800 MMBTU per day at Charleston and 92,700 MMBTU per day at Salley.

PSNC Energy’s natural gas system consists of 613 miles of transmission pipeline of up to 24 inches in diameter that connect its distribution systems with Transco. PSNC Energy’s distribution system consists of 21,268 miles of distribution mains and related service facilities. PSNC Energy owns one LNG plant with storage capacity of 1,000,000 MMBTU, the capacity to liquefy up to 4,000 MMBTU per day and the capacity to regasify approximately 100,000 MMBTU per day.

ITEM 3. LEGAL PROCEEDINGS

SCANA and SCE&G are subject to various claims and litigation incidental to their business operations which management anticipates will be resolved without a material impact on their respective results of operations, cash flows or financial condition. In addition, certain material regulatory and environmental matters and uncertainties, some of which remain outstanding at December 31, 2015, are described in the Rate Matters section of Note 2 and in the Environmental section of Note 10 to the consolidated financial statements of SCANA and SCE&G.

ITEM 4. MINE SAFETY DISCLOSURES

Not Applicable

EXECUTIVE OFFICERS OF SCANA CORPORATION

Executive officers are elected at the annual meeting of the Board of Directors, held immediately after the annual meeting of shareholders, and hold office until the next such annual meeting, unless (1) a resignation is submitted, (2) the Board of Directors shall otherwise determine or (3) as provided in the By-laws of SCANA. Positions held are for SCANA and all subsidiaries unless otherwise indicated.

Name	Age	Positions Held During Past Five Years	Dates
Kevin B. Marsh	60	Chairman of the Board and Chief Executive Officer	2011-present
		President and Chief Operating Officer-SCANA	*-present
		President-SCE&G	*-2011
Jimmy E. Addison	55	Executive Vice President-SCANA	2012-present
		Chief Financial Officer	*-present
		President and Chief Operating Officer-SEMI	2014-present
		Senior Vice President	*-2012
Jeffrey B. Archie	58	Senior Vice President and Chief Nuclear Officer-SCE&G	*-present
		Senior Vice President-SCANA	*-present
Sarena D. Burch	58	Senior Vice President-Risk Management and Corporate Compliance Senior Vice President-Fuel Procurement and Asset Management-SCE&G	2016-present
		and PSNC Energy	*-2015
		Senior Vice President-SCANA	*-2015
Stephen A. Byrne	56		2011-present
		President-Generation and Transmission-SCE&G Chief Operating Officer-SCE&G	*-present
		Executive Vice President-SCANA	*-present
		Executive Vice President-Generation and Transmission-SCE&G	*-2011
D. Russell Harris	51	Senior Vice President-Gas Distribution-SCANA	2013-present
		President-Gas Operations-SCE&G	2013-present
		President and Chief Operating Officer-PSNC Energy	*-present
		Senior Vice President-SCANA	2012-2013
Kenneth R. Jackson	59		
		Senior Vice President-Economic Development, Governmental and Regulatory Affairs	2014-present
		Senior Vice President-SCANA	2014-present
		Vice President-Rates and Regulatory Services	*-2014
W. Keller Kissam	49	President of Retail Operations-SCE&G	2011-present
		Senior Vice President-SCANA	2011-present
		Senior Vice President-Retail Operations-SCE&G	*-2011
Ronald T. Lindsay	65	Senior Vice President, General Counsel and Assistant Secretary	*-present
Martin K. Phalen	61	Senior Vice President-Administration-SCANA	2012-present

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Executive officers are elected at the annual meeting of the Board of Directors, held immediately after the annual meeting of shareholders, and hold office until the next such annual meeting, unless (1) a resignation is submitted, (2) the Board of Directors shall otherwise determine or (3) as provided in the By-laws of SCANA. Positions held are for SCANA and all subsidiaries unless otherwise indicated.

Name	Age	Positions Held During Past Five Years	Dates
Kevin B. Marsh	60	Chairman of the Board and Chief Executive Officer	2011-present
		President and Chief Operating Officer-SCANA	*-present
		President-SCE&G	*-2011
Jimmy E. Addison	55	Executive Vice President-SCANA	2012-present
		Chief Financial Officer	*-present
		President and Chief Operating Officer-SEMI	2014-present
		Senior Vice President	*-2012
Jeffrey B. Archie	58	Senior Vice President and Chief Nuclear Officer-SCE&G	*-present
		Senior Vice President-SCANA	*-present
Sarena D. Burch	58	Senior Vice President-Risk Management and Corporate Compliance Senior Vice President-Fuel Procurement and Asset Management-SCE&G	2016-present
		and PSNC Energy	*-2015
		Senior Vice President-SCANA	*-2015
Stephen A. Byrne	56		2011-present
		President-Generation and Transmission-SCE&G Chief Operating Officer-SCE&G	*-present
		Executive Vice President-SCANA	*-present
		Executive Vice President-Generation and Transmission-SCE&G	*-2011
D. Russell Harris	51	Senior Vice President-Gas Distribution-SCANA	2013-present
		President-Gas Operations-SCE&G	2013-present
		President and Chief Operating Officer-PSNC Energy	*-present
		Senior Vice President-SCANA	2012-2013
Kenneth R. Jackson	59		
		Senior Vice President-Economic Development, Governmental and Regulatory Affairs	2014-present
		Senior Vice President-SCANA	2014-present
		Vice President-Rates and Regulatory Services	*-2014
W. Keller Kissam	49	President of Retail Operations-SCE&G	2011-present
		Senior Vice President-SCANA	2011-present
		Senior Vice President-Retail Operations-SCE&G	*-2011
Ronald T. Lindsay	65	Senior Vice President, General Counsel and Assistant Secretary	*-present
Martin K. Phalen	61	Senior Vice President-Administration-SCANA	2012-present
		Vice President-Gas Operations-SCE&G	*-2012

*Indicates positions held at least since February 26, 2011.

PART II

ITEM 5. MARKET FOR REGISTRANT’S COMMON EQUITY, RELATED STOCKHOLDER MATTERS, AND ISSUER PURCHASES OF EQUITY SECURITIES

SCANA Corporation:

Price Range (NYSE Composite Listing):

2015	2014

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS, AND ISSUER PURCHASES OF EQUITY SECURITIES

SCANA Corporation:

Price Range (NYSE Composite Listing):

	2015				2014			
	4th Qtr.	**3rd Qtr.**	**2nd Qtr.**	**1st Qtr.**	**4th Qtr.**	**3rd Qtr.**	**2nd Qtr.**	**1st Qtr.**
High	$ 61.95	$ 57.73	$ 56.26	$ 65.57	$ 63.41	$ 53.89	$ 53.88	$ 51.39
Low	$ 54.84	$ 50.17	$ 47.77	$ 52.03	$ 47.77	$ 48.53	$ 49.51	$ 45.58

SCANA common stock trades on the NYSE using the ticker symbol SCG. At February 19, 2016 there were 142,916,917 shares of SCANA common stock outstanding which were held by approximately 26,000 shareholders of record. For a summary of equity securities issuable under SCANA's compensation plans at December 31, 2015, see ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS.

SCANA declared quarterly dividends on its common stock of $0.545 per share in 2015 and $0.525 per share in 2014. On February 18, 2016, SCANA increased the quarterly cash dividend rate on SCANA common stock to $0.575 per share, an increase of approximately 5.5%. The next quarterly dividend is payable April 1, 2016 to shareholders of record on March 10, 2016. For a discussion of provisions that could limit the payment of cash dividends, see ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS under Liquidity and Capital Resources-Financing Limits and Related Matters and Note 3 to the consolidated financial statements for SCANA.

The following table provides information about purchases by or on behalf of SCANA or any affiliated purchaser (as defined in Rule 10b-18(a)(3) under the Securities Exchange Act of 1934) during the fourth quarter of 2015 of shares or other units of any class of SCANA's equity securities that are registered pursuant to Section 12 of the Securities Exchange Act of 1934:

Issuer Purchases of Equity Securities

	(a)	(b)	(c)	(d)
Period	Total number of shares (or units) purchased	Average price paid per share (or unit)	Total number of shares (or units) purchased as part of publicly announced plans or programs	Maximum number (or approximate dollar value) of shares (or units) that may yet be purchased under the plans or programs
October 1-31	268,139	$ 56.51	268,139	
November 1-30	71,699	$ 59.19	71,699	
December 1-31	68,761	$ 59.57	68,761	
Total	408,599		408,599	*

*On December 16, 2014 SCANA announced a program to convert from original issue to open market purchase of SCANA common stock for all applicable compensation and dividend reinvestment plans once the sales of certain subsidiaries were completed. The sales of the subsidiaries were completed in the first quarter of 2015. This program has no stated maximum number of shares that may be purchased and no stated expiration date.

SCE&G:

All of SCE&G's common stock is owned by SCANA, and no established public trading market exists for SCE&G common stock. During 2015 and 2014, SCE&G declared quarterly dividends on its common stock in the following amounts:

Declaration Date	Amount	Declaration Date	Amount

Declaration Date	Amount	Declaration Date	Amount
February 20, 2014	$ 62.5 million	February 20, 2015	$ 69.0 million
April 24, 2014	62.8 million	April 30, 2015	67.8 million
July 31, 2014	66.8 million	July 30, 2015	68.4 million
October 30, 2014	72.5 million	October 29, 2015	72.3 million

On February 18, 2016, SCE&G declared a quarterly dividend on its common stock of $72.2 million.

For a discussion of provisions that could limit the payment of cash dividends, see ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS under Liquidity and Capital Resources-Financing Limits and Related Matters and Note 3 to the consolidated financial statements for SCE&G.

ITEM 6. SELECTED FINANCIAL DATA

As of or for the Year Ended December 31,	2015	2014	2013	2012	2011
	(Millions of dollars, except statistics and per share amounts)				
SCANA:					
Statement of Income Data					
Operating Revenues	$ 4,380	$ 4,951	$ 4,495	$ 4,176	$ 4,409
Operating Income	$ 1,308	$ 1,007	$ 910	$ 859	$ 813
Net Income	$ 746	$ 538	$ 471	$ 420	$ 387
Common Stock Data					
Weighted Avg Common Shares Outstanding (Millions)	142.9	141.9	138.7	131.1	128.8
Basic Earnings Per Share	$ 5.22	$ 3.79	$ 3.40	$ 3.20	$ 3.01
Diluted Earnings Per Share	$ 5.22	$ 3.79	$ 3.39	$ 3.15	$ 2.97
Dividends Declared Per Share of Common Stock	$ 2.18	$ 2.10	$ 2.03	$ 1.98	$ 1.94
Balance Sheet Data					
Utility Plant, Net	$ 13,145	$ 12,232	$ 11,643	$ 10,896	$ 10,047
Total Assets	$ 17,146	$ 16,818	$ 15,127	$ 14,568	$ 13,476
Total Equity	$ 5,443	$ 4,987	$ 4,664	$ 4,154	$ 3,889
Short-term and Long-term Debt	$ 6,529	$ 6,581	$ 5,788	$ 5,707	$ 5,274
Other Statistics					
Electric:					
Customers (Year-End)	698,372	687,800	678,273	669,966	664,196
Total sales (Million kWh)	23,102	23,319	22,313	23,879	24,188
Generating capability-Net MW (Year-End)	5,234	5,237	5,237	5,533	5,642
Territorial peak demand-Net MW	4,970	4,853	4,574	4,761	4,885
Regulated Gas:					
Customers, excluding transportation (Year-End)	881,295	859,186	837,232	818,983	803,644
Sales, excluding transportation (Thousand Therms)	875,218	973,907	921,533	798,978	812,416
Transportation customers (Year-End)	627	656	667	663	645
Transportation volumes (Thousand Therms)	791,402	1,786,897	1,729,399	1,559,542	1,585,202

SCE&G:

Statement of Income Data

ITEM 6. SELECTED FINANCIAL DATA

As of or for the Year Ended December 31,	2015	2014	2013	2012	2011
	(Millions of dollars, except statistics and per share amounts)				
SCANA:					
Statement of Income Data					
Operating Revenues	$ 4,380	$ 4,951	$ 4,495	$ 4,176	$ 4,409
Operating Income	$ 1,308	$ 1,007	$ 910	$ 859	$ 813
Net Income	$ 746	$ 538	$ 471	$ 420	$ 387
Common Stock Data					
Weighted Avg Common Shares Outstanding (Millions)	142.9	141.9	138.7	131.1	128.8
Basic Earnings Per Share	$ 5.22	$ 3.79	$ 3.40	$ 3.20	$ 3.01
Diluted Earnings Per Share	$ 5.22	$ 3.79	$ 3.39	$ 3.15	$ 2.97
Dividends Declared Per Share of Common Stock	$ 2.18	$ 2.10	$ 2.03	$ 1.98	$ 1.94
Balance Sheet Data					
Utility Plant, Net	$ 13,145	$ 12,232	$ 11,643	$ 10,896	$ 10,047
Total Assets	$ 17,146	$ 16,818	$ 15,127	$ 14,568	$ 13,476
Total Equity	$ 5,443	$ 4,987	$ 4,664	$ 4,154	$ 3,889
Short-term and Long-term Debt	$ 6,529	$ 6,581	$ 5,788	$ 5,707	$ 5,274
Other Statistics					
Electric:					
Customers (Year-End)	698,372	687,800	678,273	669,966	664,196
Total sales (Million kWh)	23,102	23,319	22,313	23,879	24,188
Generating capability-Net MW (Year-End)	5,234	5,237	5,237	5,533	5,642
Territorial peak demand-Net MW	4,970	4,853	4,574	4,761	4,885
Regulated Gas:					
Customers, excluding transportation (Year-End)	881,295	859,186	837,232	818,983	803,644
Sales, excluding transportation (Thousand Therms)	875,218	973,907	921,533	798,978	812,416
Transportation customers (Year-End)	627	656	667	663	645
Transportation volumes (Thousand Therms)	791,402	1,786,897	1,729,399	1,559,542	1,585,202
SCE&G:					
Statement of Income Data					
Operating Revenues	$ 2,930	$ 3,091	$ 2,845	$ 2,809	$ 2,819
Operating Income	$ 934	$ 830	$ 737	$ 717	$ 654
Net Income	$ 480	$ 458	$ 391	$ 352	$ 316
Net Income Attributable to Noncontrolling Interest	$ 14	$ 12	$ 11	$ 11	$ 10
Earnings Available to Common Shareholder	$ 466	$ 446	$ 380	$ 341	$ 306
Balance Sheet Data					
Utility Plant, Net	$ 11,589	$ 10,783	$ 10,048	$ 9,375	$ 8,588
Total Assets	$ 14,765	$ 14,078	$ 12,673	$ 12,078	$ 11,006
Total Equity	$ 5,151	$ 4,757	$ 4,489	$ 4,043	$ 3,773
Short-term and Long-term Debt	$ 5,189	$ 4,989	$ 4,279	$ 4,145	$ 3,730
Other Statistics					
Electric:					
Customers (Year-End)	698,383	687,866	678,338	670,030	664,273
Total sales (Million kWh)	23,115	23,333	22,327	23,899	24,200
Generating capability-Net MW (Year-End)	5,234	5,237	5,237	5,533	5,642

Territorial peak demand-Net MW	4,970	4,853	4,574	4,761	4,885
Regulated Gas:					
Customers, excluding transportation (Year-End)	347,447	338,274	329,179	322,419	316,683
Sales, excluding transportation (Thousand Therms)	425,661	471,596	457,119	412,163	407,073
Transportation customers (Year-End)	172	173	173	166	155
Transportation volumes (Thousand Therms)	206,990	198,733	155,190	260,215	192,492

For information on the impact of certain dispositions on SCANA's selected financial data, see Note 13 to SCANA's consolidated financial statements.

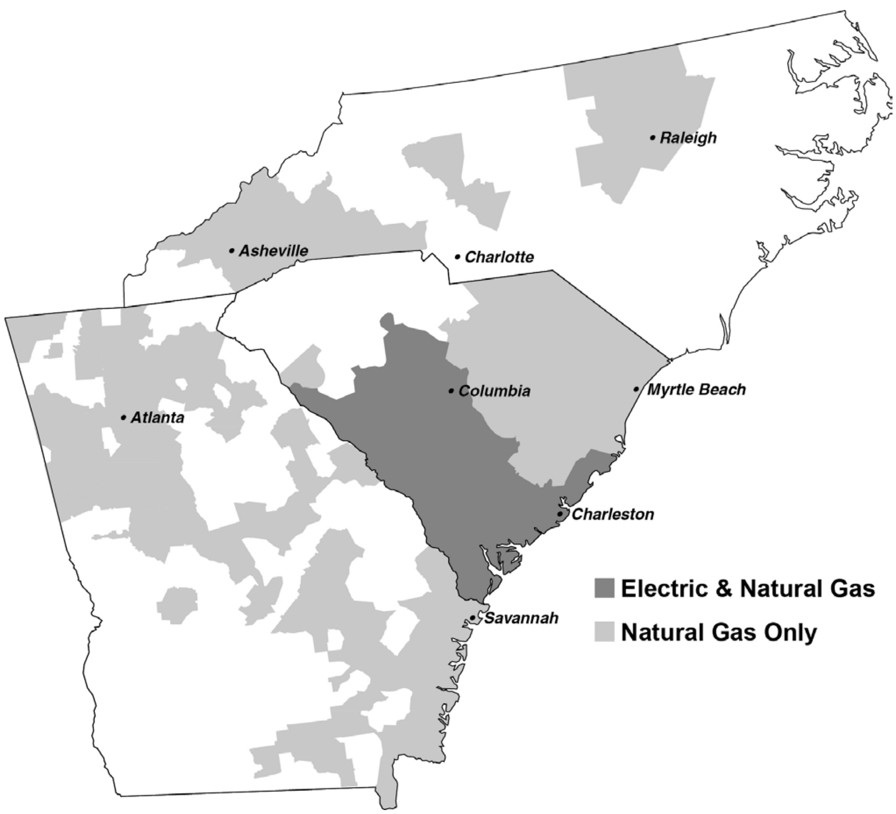
SCANA CORPORATION

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

OVERVIEW

SCANA, through its wholly-owned regulated subsidiaries, is primarily engaged in the generation, transmission, distribution and sale of electricity in South Carolina and in the purchase, transmission and sale of natural gas in North Carolina and South Carolina. Through a wholly-owned nonregulated subsidiary, SCANA markets natural gas to retail customers in Georgia and to wholesale customers in the southeast. A service company subsidiary of SCANA provides primarily administrative and management services to SCANA and its subsidiaries.

The following map indicates areas where the Company’s significant business segments conduct their activities, as further described in this overview section.



The following percentages reflect net income earned by the Company’s regulated and nonregulated businesses (including the holding company) and the percentage of total assets held by them.

	2015	2014	2013
Net Income			
Regulated	90%	98%	97%

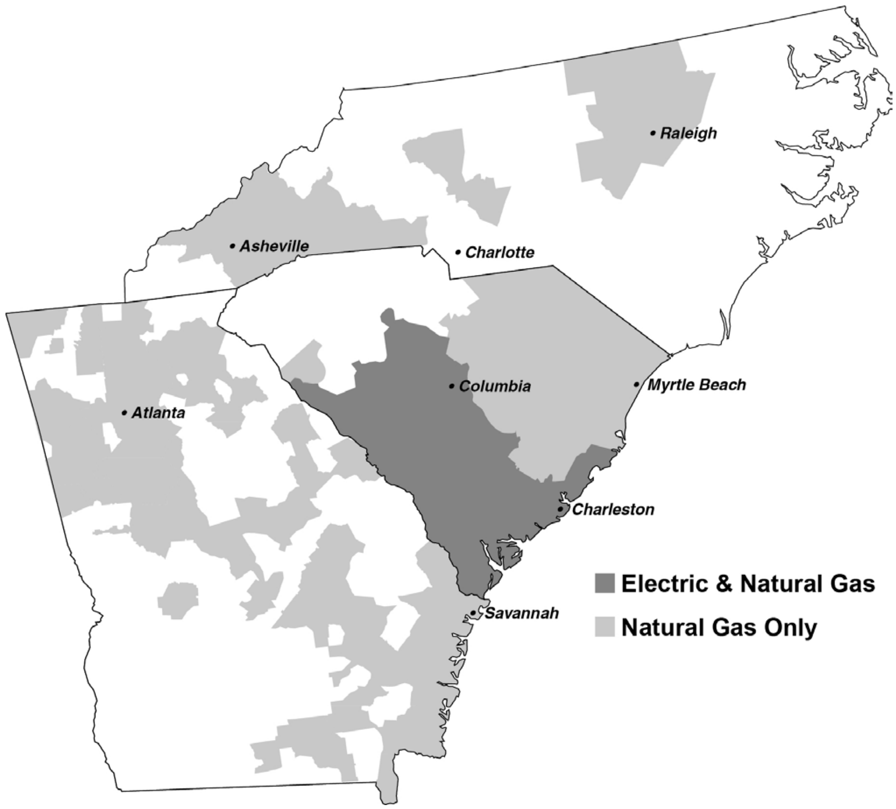
SCANA CORPORATION

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

OVERVIEW

SCANA, through its wholly-owned regulated subsidiaries, is primarily engaged in the generation, transmission, distribution and sale of electricity in South Carolina and in the purchase, transmission and sale of natural gas in North Carolina and South Carolina. Through a wholly-owned nonregulated subsidiary, SCANA markets natural gas to retail customers in Georgia and to wholesale customers in the southeast. A service company subsidiary of SCANA provides primarily administrative and management services to SCANA and its subsidiaries.

The following map indicates areas where the Company’s significant business segments conduct their activities, as further described in this overview section.



The following percentages reflect net income earned by the Company’s regulated and nonregulated businesses (including the holding company) and the percentage of total assets held by them.

	2015	2014	2013
Net Income			
Regulated	90%	98%	97%
Nonregulated	10%	2%	3%
Assets			
Regulated	97%	95%	95%
Nonregulated	3%	5%	5%

In the first quarter of 2015, SCANA closed on the sales of its interstate natural gas pipeline and telecommunications subsidiaries. The differences between 2014 and 2015 percentages of net income from regulated and nonregulated businesses are attributable to these sales. See Note 13 to the consolidated financial statements.

Key Earnings Drivers and Outlook

During 2015, economic growth continued to improve in the southeast. In the Company's South Carolina and North Carolina service territories, companies announced plans during the year to invest over $2 billion, with the expectation of creating approximately 6,500 jobs. South Carolina's unemployment rate ended December 2015 at 5.5%, a drop of 1% over 2014, an improvement that takes on greater significance when considering that almost 80,000 more South Carolinians were employed at the end of 2015 over 2014. In addition, each of the Company's regulated businesses experienced positive customer growth year over year.

Over the next five years, key earnings drivers for the Company will be additions to rate base at its regulated subsidiaries, consisting primarily of capital expenditures for new generating capacity, environmental facilities and system expansion. Other factors that will impact future earnings growth include the regulatory environment, customer growth and usage in each of the regulated utility businesses, earnings in the natural gas marketing business in Georgia and the level of growth of operation and maintenance expenses and taxes.

Electric Operations

SCE&G's electric operations primarily generates electricity and provides for its transmission, distribution and sale to approximately 698,000 customers (as of December 31, 2015) in portions of South Carolina in an area covering nearly 17,000 square miles. GENCO owns a coal-fired generating station and sells electricity solely to SCE&G. Fuel Company acquires, owns, provides financing for and sells at cost to SCE&G nuclear fuel, certain fossil fuels and emission and other environmental allowances.

Operating results are primarily driven by customer demand for electricity, rates allowed to be charged to customers and the ability to control costs. Demand for electricity is primarily affected by weather, customer growth and the economy. SCE&G is able to recover the cost of fuel used in electric generation through retail customers' bills, but increases in fuel costs affect electricity prices and, therefore, the competitive position of electricity against other energy sources.

Embedded in the rates charged to customers is an allowed regulatory return on equity. SCE&G's allowed return on equity in 2015 was 10.25% for non-BLRA rate base and 11.0% for BLRA-related rate base. To prevent the need for a non-BLRA base rate increase during years of peak nuclear construction, SCE&G has a stated goal of earning a return on equity for non-BLRA rate base of 9% or higher. For the year ended December 31, 2015, SCE&G's earned return on equity related to non-BLRA rate base was approximately 9.75%.

<u>New Nuclear Construction</u>

SCE&G, on behalf of itself and as agent for Santee Cooper, has contracted with the Consortium for the design and construction of two 1,250 MW (1,117 MW, net) nuclear generation units, which SCE&G will jointly own with Santee Cooper. SCE&G's current ownership share in the New Units is 55%, and SCE&G has agreed to acquire an additional 5% ownership from Santee Cooper in increments beginning with the commercial operation date of Unit 2. The purchase of this additional 5% ownership is expected to be funded by increased cash flows resulting from tax deductibility of depreciation associated with the New Units when they enter commercial operation.

The construction of the New Units and SCE&G's related recovery of financing costs through rates is subject to review and approval by the SCPSC as provided for in the BLRA. As of December 31, 2015, SCE&G's investment in the New Units totaled $3.6 billion, for which the financing costs on $3.2 billion have been reflected in rates under the BLRA.

In September 2015, the SCPSC approved an updated BLRA milestone schedule and certain updated owner's costs and other capital costs, some of which were associated with schedule delays and other contested costs. Also in September 2015, the SCPSC approved a revision to the allowed return on equity for new nuclear construction from 11.0% to 10.5%, to be applied prospectively for the purpose of calculating revised rates sought by SCE&G under the BLRA on and after January 1, 2016.

On October 27, 2015, SCE&G, Santee Cooper and the Consortium reached a settlement regarding certain disputes, and the EPC Contract was amended. The October 2015 Amendment became effective on December 31, 2015, and among other things, it resolved by settlement and release substantially all outstanding disputes between SCE&G and the Consortium. The October 2015 Amendment also provides SCE&G and Santee Cooper an irrevocable option, until November 1, 2016 and subject to regulatory approvals, to further amend the EPC Contract to fix the total amount to be paid to the Consortium for its entire scope of work on the project after June 30, 2015, subject to certain exceptions.

On November 19, 2015, SCE&G held an allowable *ex parte* communication briefing with the SCPSC to describe SCE&G's settlement with the Consortium. During that briefing, the Company provided the following summary of key points related to the SCPSC's September 2015 order and the October 2015 Amendment.

	SCPSC Order #2015-661 September 2015	October 2015 Amendment	Fixed Price Option Under the October 2015 Amendment

On November 19, 2015, SCE&G held an allowable *ex parte* communication briefing with the SCPSC to describe SCE&G's settlement with the Consortium. During that briefing, the Company provided the following summary of key points related to the SCPSC's September 2015 order and the October 2015 Amendment.

	SCPSC Order #2015-661 September 2015	**October 2015 Amendment**	**Fixed Price Option Under the October 2015 Amendment**
Guaranteed Substantial Completion Dates	Unit 2 - June 2019 Unit 3 - June 2020	Unit 2 - August 2019 Unit 3 - August 2020	
Capital Cost (SCE&G's 55% share)	$5.247 billion	$5.492 billion	$6.757 billion
Future Escalation to WEC*	$794 million	$813 million	$19 million
Total Expected Project Cost (SCE&G's 55% share)	$6.827 billion	$7.113 billion	$7.601 billion
Liquidated Damages	$155 million at 100%$86 million - SCE&G	$926 million at 100% $509 million - SCE&G	$676 million at 100% $372 million - SCE&G
Bonuses	Capacity Performance Related	Completion - Capacity Performance bonus removed $550 million at 100% $303 million - SCE&G	$300 million at 100% $165 million - SCE&G
Change in Law Language	Generally defined	Explicitly defined - Formal written adoption of a new statute, regulation, requirement, or code or new NRC regulatory requirement that did not exist as of this amendment	

* The fixed price option, regardless of date of acceptance, would fix project costs and shift the risk of escalation (excluding escalation primarily on owner's and transmission costs) to WEC as of June 30, 2015. Total gross escalation recorded as of June 30, 2015 is $386 million. Under the fixed price option, total gross escalation remaining on the project is estimated to be approximately $145 million.

Following an evaluation as to whether to exercise the fixed price option, SCE&G expects to file a petition, as provided under the BLRA, for an update to the project's estimated capital cost schedule which would incorporate the impact of the October 2015 Amendment. Refer to the Exhibit Index for information on where a copy of the October 2015 Amendment is available publicly.

The information summarized above, as well as additional information on these and other related matters, is further discussed at Note 2 and Note 10 to the consolidated financial statements.

Environmental

EPA regulations have a significant impact on the Company's electric operations. In 2015, several regulations were proposed or became final, including the following:

- On June 29, 2015, the Supreme Court ruled that the EPA unreasonably failed to consider costs in its decision to regulate mercury and other specified air pollutants under the MATS rule, but did not vacate MATS. The EPA has indicated that it expects to issue a revised rule responsive to the issue raised by the Supreme Court by April 15, 2016. SCE&G and GENCO have received a one-year extension (until April 2016) to comply with MATS at certain of their generating stations. These extensions will allow time to convert one generating station to burn natural gas and to install additional pollution control devices at other generating stations. SCE&G and GENCO currently are in compliance with the MATS rule and expect to remain in compliance.

- A revised standard for new power plants under the CAA was proposed on August 3, 2015, and requires all new fossil fuel-fired power plants to meet the carbon dioxide emissions profile of a combined cycle natural gas plant. This rule effectively prevents construction of new coal-fired plants without partial carbon capture and sequestration capabilities.

- On August 3, 2015, the EPA issued its final rule under the Clean Power Plan that would regulate carbon dioxide emissions from existing units. This rule includes state-specific goals for reducing national carbon dioxide emissions by 32% from 2005 levels by 2030. The rule provides for nuclear reactors under construction, such as the New Units, to count towards compliance and establishes a phased-in compliance approach beginning in 2022. The rule gives states from one to three years to issue SIPs, which will ultimately define the specific compliance methodology that will be

applied to existing units in that state. It is expected that South Carolina will request a two-year extension (until September 2018). On February 9, 2016, the Supreme Court stayed the rule pending disposition of a petition of review of the rule in the Court of Appeals. The applied to existing units in that state. It is expected that South Carolina will request a two-year extension (until September 2018). On February 9, 2016, the Supreme Court stayed the rule pending disposition of a petition of review of the rule in the Court of Appeals. The order of the Supreme Court has no immediate impact on SCE&G and GENCO or their generation operations. Any costs incurred to comply with such rule are expected to be recoverable through rates.

- The CWA provides for the imposition of effluent limitations that require treatment for wastewater discharges. Under the CWA, compliance with applicable limitations is achieved in connection with the renewal (every five years) of state-issued NPDES permits. The ELG Rule became effective January 4, 2016. SCE&G and GENCO expect that wastewater treatment technology retrofits will be required at two generating stations and may be required at other facilities. The extent of the station-specific retrofits required and the related schedule for compliance will be determined in connection with each plant's NPDES permit renewal.

- New federal regulations affecting the management and disposal of CCRs became effective in the fourth quarter of 2015. Under these regulations, CCRs will not be regulated as hazardous waste. These regulations do impose certain requirements on ash storage ponds at SCE&G's and GENCO's generating facilities. These regulations are not expected to have a material effect on SCE&G and GENCO because SCE&G and GENCO have already closed or have begun the process of closure of all of their ash storage ponds.

The above environmental initiatives and similar issues are described in Environmental Matters herein and in Note 10 to the consolidated financial statements. Unless otherwise noted, the Company cannot predict when regulatory rules or legislative requirements for any of these initiatives will become final, if at all, or what conditions they may impose on the Company, if any. The Company believes that any additional costs imposed by such regulations would be recoverable through rates.

Gas Distribution

The local distribution operations of SCE&G and PSNC Energy purchase, transport and sell natural gas to approximately 881,000 retail customers (as of December 31, 2015) in portions of South Carolina and North Carolina in areas covering approximately 35,000 square miles. Operating results for gas distribution are primarily influenced by customer demand for natural gas, rates allowed to be charged to customers and the ability to control costs. Embedded in the rates charged to customers is an allowed regulatory return on equity of 10.25% for SCE&G and 10.60% for PSNC Energy.

Demand for natural gas is primarily affected by weather, customer growth, the economy and the availability and price of alternate fuels. Natural gas competes with electricity, propane and heating oil to serve the heating and, to a lesser extent, other household energy needs of residential and small commercial customers. This competition is generally based on price and convenience. Large commercial and industrial customers often have the ability to switch from natural gas to an alternate fuel, such as propane or fuel oil. Natural gas competes with these alternate fuels based on price. As a result, any significant disparity between supply and demand, either of natural gas or of alternate fuels, and due either to production or delivery disruptions or other factors, will affect price and will impact the Company’s ability to retain large commercial and industrial customers.

The production of shale gas in the United States continues to keep prices for this commodity at historic lows, and such prices are expected to continue at such levels for the foreseeable future. The supply of natural gas from the Marcellus and Utica shale basins in West Virginia, Pennsylvania and Ohio has prompted companies unaffiliated with SCANA to propose a 550-mile pipeline that would bring natural gas from these basins to Virginia and North Carolina. If successful, the completed pipeline may drive economic development along its path, including areas within PSNC Energy's service territory, and may serve to keep natural gas competitively priced in the region.

Retail Gas Marketing

SCANA Energy, a division of SEMI, sells natural gas to approximately 450,000 customers (as of December 31, 2015) throughout Georgia. This market is mature, resulting in lower margins and stiff competition. Competitors include affiliates of large energy companies as well as electric membership cooperatives, among others. SCANA Energy’s ability to maintain its market share primarily depends on the prices it charges customers relative to the prices charged by its competitors and its ability to provide high levels of customer service. In addition, SCANA Energy's operating results are sensitive to weather.

As Georgia’s regulated provider, SCANA Energy provides service to customers considered to be low-income or that are otherwise unable to obtain natural gas service from other marketers. SCANA Energy provides this service at rates approved

by the GPSC and receives funding from Georgia's Universal Service Fund to offset some of the resulting bad debt. SCANA Energy files financial and other information periodically with the GPSC, and such information is available at *www.psc.state.ga.us* (which is not intended as an active hyperlink; the information on the GPSC website is not part of this or any other report filed by the Company with the SEC).

SCANA Energy and certain of SCANA’s other natural gas distribution and marketing segments maintain gas inventory and utilize forward contracts and other financial instruments, including commodity swaps and futures contracts, to manage exposure to fluctuating commodity natural by the GPSC and receives funding from Georgia's Universal Service Fund to offset some of the resulting bad debt. SCANA Energy files financial and other information periodically with the GPSC, and such information is available at *www.psc.state.ga.us* (which is not intended as an active hyperlink; the information on the GPSC website is not part of this or any other report filed by the Company with the SEC).

SCANA Energy and certain of SCANA’s other natural gas distribution and marketing segments maintain gas inventory and utilize forward contracts and other financial instruments, including commodity swaps and futures contracts, to manage exposure to fluctuating commodity natural gas prices. See Note 6 to the consolidated financial statements. As a part of this risk management process, at any given time, a portion of SCANA’s projected natural gas needs has been purchased or placed under contract.

Energy Marketing

The divisions of SEMI, excluding SCANA Energy, market natural gas in the southeast and provide energy-related services to customers. Operating results for energy marketing are primarily influenced by customer demand for natural gas and the ability to control costs. The price of alternate fuels and customer growth significantly affect demand for natural gas. In addition, certain pipeline capacity available for Energy Marketing to serve industrial and other customers is dependent upon the market share held by SCANA Energy in the retail market.

RESULTS OF OPERATIONS

Earnings Per Share

The Company reports earnings determined in accordance with GAAP. Management believes that, in addition to reported earnings under GAAP, the Company's GAAP-adjusted weather-normalized net earnings (and earnings per share) provide a meaningful representation of its fundamental earnings power and can aid in performing period-over-period financial analysis and comparison with peer group data. In management's opinion, in addition to operating income for regulated businesses, GAAP-adjusted weather-normalized net earnings (and earnings per share) are a useful indicator of the financial results of the Company's primary businesses. These measures are also a basis for management's provision of earnings guidance and growth projections and are used in part by management in making budgetary and operational decisions including determining eligibility for certain incentive compensation payments. These non-GAAP performance measures are not intended to replace the GAAP measures of net earnings (or earnings per share), but are offered as supplements to it. A reconciliation of GAAP earnings per share to GAAP-adjusted weather-normalized net earnings per share follows:

	2015	2014	2013
GAAP basic earnings per share	$ 5.22	$ 3.79	$ 3.40
Deduct:			
Gain on sale of CGT	0.95	—	—
Gain on sale of SCI	0.46	—	—
SCE&G Electric - effect of abnormal weather	0.08	0.21	—
GAAP-adjusted weather-normalized basic earnings per share	$ 3.73	$ 3.58	$ 3.40
GAAP diluted earnings per share	$ 5.22	$ 3.79	$ 3.39
GAAP-adjusted weather-normalized diluted earnings per share	$ 3.73	$ 3.58	$ 3.39
Cash dividends declared per share	$ 2.18	$ 2.10	$ 2.03

2015 vs 2014

Earnings per share on a GAAP basis increased due to the sale of CGT and SCI, higher electric margins, lower operation and maintenance expenses and lower depreciation expense. These increases were partially offset by lower gas margins, higher property taxes, lower other income, higher interest expense, a higher effective tax rate and dilution from additional shares outstanding, as further described below.

2014 vs 2013

Basic earnings per share on a GAAP basis increased primarily due to the effects of weather, customer growth and base rate increases under the BLRA. Higher electric and gas margins were partially offset by higher operation and maintenance expenses, higher depreciation expense, higher property taxes, dilution from additional shares outstanding and higher interest expense, as further described below.

Discussion of above adjustments:

The sales of CGT and SCI were closed in the first quarter of 2015. These subsidiaries operated principally in wholesale markets, whereas

2014 vs 2013

Basic earnings per share on a GAAP basis increased primarily due to the effects of weather, customer growth and base rate increases under the BLRA. Higher electric and gas margins were partially offset by higher operation and maintenance expenses, higher depreciation expense, higher property taxes, dilution from additional shares outstanding and higher interest expense, as further described below.

Discussion of above adjustments:

The sales of CGT and SCI were closed in the first quarter of 2015. These subsidiaries operated principally in wholesale markets, whereas the Company's primary focus is the delivery of energy-related products and services to retail markets. Therefore, CGT and SCI were not a part of the Company's core business. See Note 13 to the consolidated financial statements. In aggregate, these subsidiaries contributed basic earnings per share of $.02 in 2015, $.14 in 2014 and $.15 in 2013.

SCE&G estimates the effects of abnormal weather on its electric business by comparing actual temperatures in its service territory to a historical average. The result is used in developing an estimate of electric margin revenue, using average margin rates, attributable to the effects of abnormal weather. In 2013 the Company's eWNA was still in place, so therefore there was no effect of abnormal weather on the Company's electric margin. In January 2014 the eWNA was terminated by order of the SCPSC.

Management believes the above adjustments are appropriate in determining the non-GAAP financial performance measures. Such non-GAAP measures reflect management's decision that wholesale gas transportation and telecommunications operations were not a part of the Company's core businesses and would not align with the Company's commitment to serve retail customers on a long-term basis. The non-GAAP measures also provide a consistent basis upon which to measure performance by excluding the effects on per share earnings of abnormal weather in the electric business.

Diluted earnings per share figures give effect to dilutive potential common stock using the treasury stock method. See Note 1 to the consolidated financial statements.

On February 18, 2016, SCANA declared a quarterly cash dividend on its common stock of $.575 per share.

Electric Operations

Electric Operations is comprised of the electric operations of SCE&G, GENCO and Fuel Company. Electric operations sales margin (including transactions with affiliates) was as follows:

Millions of dollars	**2015**	**Change**	**2014**	**Change**	**2013**
Operating revenues	$ 2,557.1	(2.7)%	$ 2,629.4	8.2%	$ 2,430.5
Less: Fuel used in electric generation	660.6	(17.4)%	799.3	6.4%	751.0
Purchased power	52.1	(35.4)%	80.7	87.7%	43.0
Margin	1,844.4	5.4 %	1,749.4	6.9%	1,636.5
Other operation and maintenance expenses	497.1	0.5 %	494.8	3.2%	479.6
Depreciation and amortization	277.3	(7.7)%	300.3	1.2%	296.7
Other taxes	194.5	4.2 %	186.7	3.2%	180.9
Operating Income	$ 875.5	14.1 %	$ 767.6	13.0%	$ 679.3

2015 vs 2014

- Margin increased due to downward adjustments of $69.0 million in 2014, compared to downward adjustments of $19.7 million in 2015, pursuant to orders of the SCPSC, related to fuel cost recovery and DSM Programs. These adjustments had no effect on net income as they were fully offset by the recognition, within other income, of gains realized upon the late 2013 settlement of certain derivative interest rate contracts, lower depreciation expense upon the adoption and implementation of revised depreciation rates as a result of an updated depreciation study and the application, as a reduction to operation and maintenance expenses, of a portion of the storm damage reserve. Margin also increased due to base rate increases under the BLRA of $65.7 million and residential and commercial customer growth of $21.4 million. These increases were partially offset by $25.6 million due to the effects of weather, lower industrial margins of $14.6 million primarily due to variable price contracts, and lower collections under the rate rider for pension costs of $3.0 million. See Note 2 to the consolidated financial statements.

- Operations and maintenance expenses increased due to the application of $5.0 million in 2014 of the storm damage reserve to offset downward revenue adjustments related to DSM Programs and the amortization of $3.7 million of DSM Programs cost. These increases were partially offset by lower labor costs of $2.0 million primarily due to lower pension cost recognition as a result of lower rate rider

- Operations and maintenance expenses increased due to the application of $5.0 million in 2014 of the storm damage reserve to offset downward revenue adjustments related to DSM Programs and the amortization of $3.7 million of DSM Programs cost. These increases were partially offset by lower labor costs of $2.0 million primarily due to lower pension cost recognition as a result of lower rate rider collections.
- Depreciation and amortization decreased by $28.7 million in 2015 due to the implementation of the above mentioned revised depreciation rates, $14.5 million of which was offset by downward revenue adjustments. This decrease in depreciation expense was partially offset by increases associated with net plant additions.
- Other taxes increased due primarily to higher property taxes associated with net plant additions.

2014 vs 2013

- Electric margin increased due to the effects of weather of $43.5 million, base rate increases under the BLRA of $54.1 million and customer growth of $14.7 million. These margin increases were partially offset by downward adjustments of $69.0 million in 2014, compared to downward adjustments of $50.1 million in 2013, pursuant to SCPSC orders related to fuel cost recovery, the reversal of undercollected amounts related to SCE&G's eWNA program (the eWNA was discontinued effective with the first billing cycle of 2014) and DSM Programs. Such adjustments are fully offset by the recognition within other income of gains realized upon the late 2013 settlement of certain derivative interest rate contracts and the application, as a reduction to operation and maintenance expenses, of a portion of the storm damage reserve, both of which had been deferred in regulatory accounts. See Note 2 to the consolidated financial statements.
- Operations and maintenance expenses increased due to nonlabor operating expenses of $8.9 million, DSM Programs cost amortization of $2.1 million, higher labor expense of $1.1 million which includes incentive compensation and lower pension cost recognition, storm expenses of $1.1 million and other general expenses of $1.9 million.
- Depreciation and amortization increased due to net plant additions.
- Other taxes increased due primarily to higher property taxes associated with net plant additions.

Sales volumes (in GWh) related to the electric margin above, by class, were as follows:

Classification	2015	Change	2014	Change	2013
Residential	7,978	(2.2)%	8,156	7.7	7,571
Commercial	7,386	0.2 %	7,371	2.3%	7,205
Industrial	6,201	(0.5)%	6,234	3.9%	6,000
Other	595	(0.8)%	600	3.3%	581
Total retail sales	22,160	(0.9)%	22,361	4.7%	21,357
Wholesale	942	(1.7)%	958	0.3%	955
Total Sales	23,102	(0.9)%	23,319	4.5%	22,312

2015 vs 2014

Retail sales volumes decreased primarily due to the effects of weather, partially offset by customer growth.

2014 vs 2013

Retail sales volumes increased primarily due to the effects of weather and customer growth.

Gas Distribution

Gas Distribution is comprised of the local distribution operations of SCE&G and PSNC Energy. Gas Distribution sales margin (including transactions with affiliates) was as follows:

Millions of dollars	2015	Change	2014	Change	2013
Operating revenues	$ 811.7	(20.0)%	$ 1,014.0	7.6%	$ 942.6
Less: Gas purchased for resale	383.7	(35.2)%	592.5	10.8%	534.9
Margin	428.0	1.5 %	421.5	3.4%	407.7
Other operation and maintenance expenses	161.4	4.3 %	154.8	1.4%	152.7
Depreciation and amortization	77.5	7.0 %	72.4	3.6%	69.9
Other taxes	37.5	7.8 %	34.8	8.1%	32.2
Operating Income	$ 151.6	(5.0)%	$ 159.5	4.3%	$ 152.9

2015 vs 2014

- Margin increased due to residential and commercial customer growth of $7.8 million partially offset by a decrease of $3.1 million at SCE&G due to a SCPSC-approved decrease in base rates under the RSA effective November 2014.
- Operation and maintenance expenses increased due to higher labor costs, primarily due to incentive compensation.
- Depreciation and amortization increased due to net plant additions.
- Other taxes increased due primarily to higher property taxes associated with net plant additions.

2014 vs 2013

- Margin increased primarily due to residential and commercial customer growth of $9.1 million and increased average usage at SCE&G of $2.5 million.
- Operations and maintenance expense increased $0.9 million due to labor.
- Depreciation and amortization increased due to net plant additions.
- Other taxes increased due primarily to higher property taxes associated with net plant additions.

Sales volumes (in MMBTU) by class, including transportation gas, were as follows:

Classification (in thousands)	2015	Change	2014	Change	2013
Residential	39,090	(15.4)%	46,207	12.0 %	41,268
Commercial	28,064	(8.6)%	30,701	8.9 %	28,181
Industrial	20,101	(1.2)%	20,343	(8.9)%	22,319
Transportation gas	49,297	8.3 %	45,506	7.8 %	42,221
Total	136,552	(4.3)%	142,757	6.5 %	133,989

2015 vs 2014

Residential and commercial firm sales volumes decreased due to the effects of weather and lower average use, partially offset by customer growth. Commercial and industrial interruptible volumes decreased due to a shift to transportation service from system supply and the impact of curtailments, partially offset by lower curtailments at PSNC Energy. Transportation volumes increased due to customers shifting to transportation-only service at SCE&G and increased sales for natural gas fired electric generation in PSNC Energy's territory.

2014 vs 2013

Total sales volumes increased primarily due to weather and residential and commercial customer growth. Industrial sales volumes decreased primarily due to weather-related curtailments and a customer switching to an alternative fuel source. Transportation sales increased due to an increase in natural gas fired generation, partially offset by curtailments.

Retail Gas Marketing

Retail Gas Marketing is comprised of SCANA Energy, which operates in Georgia’s natural gas market. Retail Gas Marketing operating revenues and net income were as follows:

Millions of dollars	2015	Change	2014	Change	2013
Operating revenues	$ 449.2	(12.8)%	$ 514.9	10.7%	$ 465.2
Net Income	18.6	(28.2)%	25.9	8.8%	23.8

Changes in operating revenues are primarily related to the lower price of natural gas and weather-related changes in demand. Changes in net income are primarily due to weather-related changes in demand.

Energy Marketing

Energy Marketing is comprised of the Company’s nonregulated marketing operations, excluding SCANA Energy. Energy Marketing operating revenues and net income were as follows:

Millions of dollars	2015	Change	2014	Change	2013
Operating revenues	$ 697.5	(28.9)%	$ 981.5	19.9 %	$ 818.5
Net Income	9.0	76.5 %	5.1	(16.4)%	6.1

2015 vs 2014

Operating revenues decreased due to lower industrial sales volume and lower market prices. Net income increased due to lower cost of gas and lower costs of transportation to serve customers.

2014 vs 2013

Operating revenues increased due to higher industrial sales volume and higher market prices. Net income decreased due to higher cost to serve customers during periods of pipeline constraints.

Other Operating Expenses

Other operating expenses were as follows:

Millions of dollars	2015	Change	2014	Change	2013
Other operation and maintenance	$ 715.3	(1.8)%	$ 728.3	2.9%	$ 707.5
Depreciation and amortization	357.5	(6.8)%	383.7	1.5%	378.1
Other taxes	234.2	2.4 %	228.8	4.1%	219.7

Changes in other operating expenses are largely attributable to the electric operations and gas distribution segments and are addressed in those discussions. Additional information on a consolidated basis is provided below.

2015 vs 2014

In addition to factors discussed in the electric operations and gas distribution segments, other operation and maintenance expenses decreased by $24.2 million, depreciation and amortization decreased by $7.8 million and other taxes decreased by $8 million due to the sale of CGT.

2014 vs 2013

See discussion in the electric operations and gas distribution segments.

Net Periodic Benefit Cost

Net periodic benefit cost was recorded on the Company's income statements and balance sheets as follows:

Millions of dollars	2015	Change	2014	Change	2013
Income Statement Impact:					
Employee benefit costs	$ 5.3	6.0%	$ 5.0	(67.7)%	$ 15.5
Other expense	1.1	*	0.2	(80.0)%	1.0
Balance Sheet Impact:					
Increase in capital expenditures	3.9	*	0.5	(93.1)%	7.2
Component of amount receivable from Summer Station co-owner	1.5	*	0.1	(96.0)%	2.5
Increase (decrease) in regulatory assets	6.2	*	(3.2)	*	5.5
Net periodic benefit cost	$ 18.0	*	$ 2.6	(91.8)%	$ 31.7

* Greater than 100%

Pursuant to regulatory orders, SCE&G recovers current pension expense through a rate rider (for retail electric operations) and through cost of service rates (for gas operations), and amortizes pension costs previously deferred in regulatory assets as further described in Note 2 and Note 8 to the consolidated financial statements. Amounts amortized were as follows:

Millions of dollars	2015	2014	2013
Retail electric operations	$ 2.0	$ 2.0	$ 2.0
Gas operations	1.0	1.0	0.2

Other Income (Expense)

Other income (expense) includes the results of certain incidental activities of regulated subsidiaries, the activities of certain non-regulated subsidiaries, and AFC. AFC is a utility accounting practice whereby a portion of the cost of both equity and borrowed funds used to finance construction (which is shown on the balance sheet as construction work in progress) is capitalized. The Company includes an equity portion of AFC in nonoperating income and a debt portion of AFC in interest charges (credits) as noncash items, both of which have the effect of increasing reported net income. Components of other income (expense) were as follows:

Millions of dollars	2015	Change	2014	Change	2013
Other income	$ 74.5	(38.8)%	$ 121.8	21.4%	$ 100.3
Other expense	(60.1)	(6.5)%	(64.3)	41.3%	(45.5)
Gain on sale of SCI, net of transaction costs	106.6	*	—	—	—
AFC - equity funds	27.0	(17.4)%	32.7	23.4%	26.5

* Greater than 100%

2015 vs 2014

Other income decreased due primarily to the recognition of $64.0 million of gains in 2014, compared to $5.2 million in 2015, realized upon the settlement of certain interest rate contracts previously recorded as regulatory liabilities pursuant to the SCPSC orders previously discussed. Such gain recognition was fully offset by downward adjustments to revenues reflected within electric margin and had no effect on net income (see electric margin discussion). Other income decreased by $18.3 million and other expenses decreased by $10.9 million due to the sale of SCI. Total other income and other expenses increased by $12.7 million for billings to DCGT for transition services provided at cost pursuant to the terms of the sale of CGT. In 2015 other income also included the gain on the sale of SCI (See Note 13 to the consolidated financial statements). AFC decreased due to lower AFC rates.

2014 vs 2013

Other income (expense) increased primarily due to the recognition of $64.0 million of gains realized upon the late 2013 settlement of certain interest rate derivative contracts previously recorded as regulatory liabilities pursuant to SCPSC orders previously discussed, compared to $50.1 million of such gains in 2013. Such gain recognition was fully offset by downward adjustments to revenues reflected within electric margin and had no effect on net income.

Interest Expense

Components of interest expense, net of the debt component of AFC, were as follows:

Millions of dollars	2015	Change	2014	Change	2013
Interest on long-term debt, net	$ 311.3	1.5%	$ 306.7	4.7%	$ 292.8
Other interest expense	6.5	14.0%	5.7	23.9%	4.6
Total	$ 317.8	1.7%	$ 312.4	5.0%	$ 297.4

Interest on long-term debt increased in each year primarily due to increased borrowings.

Income Taxes

Income tax expense increased each year primarily due to increases in income before taxes. Income before taxes, income taxes and the effective tax rate were all higher in 2015 primarily due to the sales of CGT and SCI.

LIQUIDITY AND CAPITAL RESOURCES

The Company anticipates that its contractual cash obligations will be met in 2016 through internally generated funds and additional short- and long-term borrowings. In 2017 and beyond, the Company may also meet such obligations through the sale of equity securities. The Company expects that, barring a future impairment of the capital markets, it has or can obtain adequate sources of financing to meet its projected cash requirements for the foreseeable future, including the cash requirements for nuclear construction and refinancing maturing long-term debt.

Cash requirements for SCANA's regulated subsidiaries arise primarily from their operational needs, funding their construction programs and payment of dividends to SCANA. The ability of the regulated subsidiaries to replace existing plant investment, to expand to meet future demand for electricity and gas and to install equipment necessary to comply with environmental regulations, will depend on their ability to attract the necessary financial capital on reasonable terms. Regulated subsidiaries recover the costs of providing services through rates charged to customers. Rates for regulated services are generally based on historical costs. As customer growth and inflation occur and these subsidiaries continue their ongoing construction programs, rate increases will be sought. The future financial position and results of operations of regulated subsidiaries will be affected by their ability to obtain adequate and timely rate and other regulatory relief.

Due primarily to the availability of proceeds from the sale of two subsidiaries in the first quarter of 2015, the Company began using open market purchases for its stock plans at the end of January 2015. Prior to the use of open market purchases, SCANA common stock was acquired on behalf of participants in SCANA’s Investor Plus Plan and Stock Purchase-Savings Plan through the original issuance of shares. This provided additional equity of approximately $14 million in 2015, $98 million in 2014 and $99 million in 2013. In addition, in March 2013, SCANA settled all forward sales contracts related to its common stock through the issuance of approximately 6.6 million common shares, resulting in net proceeds of approximately $196 million.

Rating agencies consider qualitative and quantitative factors when assessing SCANA and its rated operating companies’ credit ratings, including regulatory environment, capital structure and the ability to meet liquidity requirements. Changes in the regulatory environment or deterioration of the Company’s commonly monitored financial credit metrics could adversely affect the Company’s debt ratings. This could cause the Company to pay higher interest rates on its long- and short-term indebtedness, and could limit the Company's access to capital markets and liquidity.

Capital Expenditures

Cash outlays for property additions and construction expenditures, including nuclear fuel, were $1.2 billion in 2015. The Company’s current estimates of its capital expenditures for construction and nuclear fuel for the next three years, which are subject to continuing review and adjustment, are as follows:

Estimated Capital Expenditures

Millions of dollars	**2016**	**2017**	**2018**
SCE&G - Normal			
Generation	$ 88	$ 130	$ 91
Transmission & Distribution	192	163	187
Other	12	9	15
Gas	61	63	60
Common	3	2	4
Total SCE&G - Normal	356	367	357
PSNC Energy	198	279	212
Other	27	30	21
Total Normal	581	676	590
New Nuclear (including transmission)	1,166	1,013	677
Cash Requirements for Construction	1,747	1,689	1,267
Nuclear Fuel	122	80	89
Total Estimated Capital Expenditures	$ 1,869	$ 1,769	$ 1,356

The Company’s contractual cash obligations as of December 31, 2015 are summarized as follows:

Contractual Cash Obligations

	Payments due by periods				
Millions of dollars	**Total**	**Less than 1 year**	**1 - 3 years**	**4 - 5 years**	**More than 5 years**
Long- and short-term debt, including interest	$ 12,599	$ 958	$ 1,635	$ 1,345	$ 8,661
Capital leases	18	6	9	1	2
Operating leases	59	10	19	6	24
Purchase obligations	4,171	1,950	2,108	112	1
Other commercial commitments	4,273	847	1,776	950	700
Total	$ 21,120	$ 3,771	$ 5,547	$ 2,414	$ 9,388

Included in the table above in purchase obligations is SCE&G’s portion of a contractual agreement for the design and construction of the New Units at Summer Station. SCE&G expects to be a joint owner and share operating costs and generation output of the New Units, with SCE&G currently responsible for 55 percent. SCE&G estimates it will cost $750 million to $850 million to acquire an additional 5% ownership in the New Units and has included $750 million for this purpose in other commercial commitments. See also New Nuclear Construction in Note 10 to the consolidated financial statements.

Purchase obligations include customary purchase orders under which the Company has the option to utilize certain vendors without the obligation to do so. The Company may terminate such arrangements without penalty.

Other commercial commitments includes estimated obligations under forward contracts for natural gas purchases. Such forward contracts include customary “make-whole” or default provisions, but are not considered to be “take-or-pay” contracts. Certain of these contracts relate to regulated businesses; therefore, the effects of such contracts on fuel costs are reflected in electric or gas rates. Other commercial commitments also includes a “take-and-pay” contract for natural gas which expires in 2019 and estimated obligations for coal and nuclear fuel purchases.

In addition to the contractual cash obligations above, the Company sponsors a noncontributory defined benefit pension plan and an unfunded health care and life insurance benefit plan for retirees. The pension plan is adequately funded under current regulations, and no significant contributions are anticipated for the foreseeable future. Cash payments under the postretirement health care and life insurance benefit plan were $10.3 million in 2015, and such annual payments are expected to be the same or increase to as much as $12.3 million in the future.

The Company is party to certain NYMEX natural gas futures contracts for which any unfavorable market movements are funded in cash. These derivatives are accounted for as cash flow hedges and their effects are reflected within other comprehensive income until the anticipated sales transactions occur. The Company is also party to certain interest rate derivative contracts for which unfavorable market movements above certain thresholds are funded in cash. Certain of these interest rate derivative contracts are accounted for as cash flow hedges, and others are not designated as cash flow hedges but are accounted for pursuant to regulatory orders. See further discussion at ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK and Note 6 to the consolidated financial statements. At December 31, 2015, the Company had posted $14.3 million in cash collateral for such natural gas futures contracts, and had posted $36.1 million in cash collateral related to interest rate derivative contracts.

In connection with the effectiveness of the October 2015 Amendment, SCE&G accrued within accounts payable $250 million (SCE&G's 55% share is $137.5 million) as of December 31, 2015 for the settlement and release of substantially all outstanding disputes between SCE&G and the Consortium. These amounts are not included in capital expenditures and contractual cash obligations above. See Note 10 to the consolidated financial statements.

The Company has a legal obligation associated with the decommissioning and dismantling of Summer Station Unit 1 and other conditional AROs that are not listed in contractual cash obligations above. See Notes 1 and 10 to the consolidated financial statements. In addition, the Company has recorded liabilities for certain unrecognized tax benefits that are not included in contractual cash obligations above. See Note 5 to the consolidated financial statements.

Financing Limits and Related Matters

The Company’s issuance of various securities, including long-term and short-term debt, is subject to customary approval or authorization by regulatory bodies including state public service commissions and FERC.

SCE&G has obtained FERC authority to issue short-term indebtedness and to assume liabilities as a guarantor(pursuant to Section 204 of the Federal Power Act). SCE&G may issue unsecured promissory notes, commercial paper and direct loans in amounts not to exceed $1.6 billion outstanding with maturity dates of one year or less, and may enter into guaranty agreements in favor of lenders, banks, and dealers in commercial paper in amounts not to exceed $600 million. GENCO has obtained FERC authority to issue short-term indebtedness not to exceed $200 million outstanding with maturity dates of one year or less. The authority described herein will expire in October 2016.

In December 2015, the Company's existing five-year committed LOCs were amended, extended and, in some cases, upsized. At December 31, 2015 SCANA, SCE&G (including Fuel Company) and PSNC Energy were parties to five-year credit agreements in the amounts of $400 million, $1.2 billion, of which $500 million relates to Fuel Company, and $200 million, respectively, which expire in December 2020. In addition, at December 31, 2015 SCE&G was party to a three-year credit agreement in the amount of $200 million which expires in December 2018. These credit agreements are used for general corporate purposes, including liquidity support for each company's commercial paper program and working capital needs and, in the case of Fuel Company, to finance or refinance the purchase of nuclear fuel, certain fossil fuels, and emission and other

environmental allowances. For a list of banks providing credit support and other information, see Note 4 to the consolidated financial statements.

On January 29, 2015, SCANA entered into an unsecured, three-month credit agreement in the amount of $150 million to ensure sufficient environmental allowances. For a list of banks providing credit support and other information, see Note 4 to the consolidated financial statements.

On January 29, 2015, SCANA entered into an unsecured, three-month credit agreement in the amount of $150 million to ensure sufficient liquidity was available to redeem its Junior Subordinated Notes on February 2, 2015. No borrowings were made under this agreement, and it expired according to its terms on February 6, 2015.

As of December 31, 2015, the Company had no outstanding borrowings under its $2.0 billion credit facilities, had approximately $531 million in commercial paper borrowings outstanding, was obligated under $3.3 million in LOC supported letters of credit, and held approximately $176 million in cash and temporary investments. The Company regularly monitors the commercial paper and short-term credit markets to optimize the timing for repayment of the outstanding balance on its draws, while maintaining appropriate levels of liquidity. Average short-term borrowings outstanding during 2015 were approximately $479 million. Short-term cash needs were met primarily through the issuance of commercial paper.

At December 31, 2015, the Company's long-term debt portfolio has a weighted average maturity of approximately 20 years and bears an average cost of 5.8%. Substantially all of the Company's long-term debt bears fixed interest rates or is swapped to fixed. To further preserve liquidity, the Company rigorously reviews its projected capital expenditures and operating costs and adjusts them where possible without impacting safety, reliability, and core customer service.

The Company's articles of incorporation do not limit the dividends that may be paid on its common stock. However, SCE&G's bond indenture (relating to the hereinafter defined Bonds) and PSNC Energy's note purchase and debenture purchase agreements each contain provisions that, under certain circumstances which the Company considers to be remote, could limit the payment of cash dividends on their respective common stock.

The Federal Power Act requires the appropriation of a portion of certain earnings from hydroelectric projects. At December 31, 2015, approximately $72.4 million of retained earnings were restricted by this requirement as to payment of cash dividends on SCE&G's common stock.

SCANA Corporation

SCANA has an indenture which permits the issuance of unsecured debt securities from time to time including its medium-term notes. This indenture contains no specific limit on the amount of unsecured debt securities which may be issued.

South Carolina Electric & Gas Company

SCE&G is subject to a bond indenture dated April 1, 1993 (Mortgage) covering substantially all of its electric properties under which all of its first mortgage bonds (Bonds) have been issued. Bonds may be issued under the Mortgage in an aggregate principal amount not exceeding the sum of (1) 70% of Unfunded Net Property Additions (as therein defined), (2) the aggregate principal amount of retired Bonds and (3) cash deposited with the trustee. Bonds, other than certain Bonds issued on the basis of retired Bonds, may be issued under the Mortgage only if Adjusted Net Earnings (as therein defined) for 12 consecutive months out of the 18 months immediately preceding the month of issuance are at least twice (2.0) the annual interest requirements on all outstanding Bonds and Bonds to be outstanding (Bond Ratio). For the year ended December 31, 2015, the Bond Ratio was 5.17.

Financing Activities

During 2015, net cash outflows related to financing activities totaled approximately $360 million, primarily associated with the repayment of long-term and short-term debt and payment of dividends, partially offset by proceeds from the issuance of long-term debt.

In May 2015, SCE&G issued $500 million of 5.1% first mortgage bonds due June 1, 2065. Proceeds from this sale were used to repay short-term debt primarily incurred as a result of SCE&G's construction program, to finance capital expenditures, and for general corporate purposes.

On February 2, 2015, SCANA redeemed prior to maturity $150 million of its 7.70% junior subordinated notes at their face value.

In May 2014, SCE&G issued $300 million of 4.5% first mortgage bonds due June 1, 2064. Proceeds from this sale were used to repay short-term debt primarily incurred as a result of SCE&G's construction program, to finance capital expenditures, and for general corporate purposes.

Investing Activities

To settle interest rate derivative contracts, the Company paid approximately $253 million, net, in 2015, approximately $95 million in 2014 and approximately $6 million, net, through the third quarter of 2013. During the fourth quarter of 2013, the Company received approximately $120

In May 2014, SCE&G issued $300 million of 4.5% first mortgage bonds due June 1, 2064. Proceeds from this sale were used to repay short-term debt primarily incurred as a result of SCE&G's construction program, to finance capital expenditures, and for general corporate purposes.

Investing Activities

To settle interest rate derivative contracts, the Company paid approximately $253 million, net, in 2015, approximately $95 million in 2014 and approximately $6 million, net, through the third quarter of 2013. During the fourth quarter of 2013, the Company received approximately $120 million upon the settlement of interest rate derivatives.

For additional information, see Note 4 to the consolidated financial statements.

Major tax incentives included within federal legislation resulted in the allowance of bonus depreciation for property placed in service in 2008 through 2015. These incentives, along with certain other deductions, have had a positive impact on the cash flows of the Company. Bonus depreciation will also be significant for 2016 through 2019 under recent law.

Ratios of earnings to fixed charges for each of the five years ended December 31, 2015, were as follows:

December 31,	**2015**	**2014**	**2013**	**2012**	**2011**
SCANA	4.40	3.39	3.22	2.93	2.87

The ratio for 2015 reflects the impact of gains recorded upon the sale of certain subsidiaries. See Note 13 to the consolidated financial statements.

NEW NUCLEAR CONSTRUCTION MATTERS

For a discussion of developments related to new nuclear construction, see Note 2 and Note 10 to the consolidated financial statements.

ENVIRONMENTAL MATTERS

The Company's operations are subject to extensive regulation by various federal and state authorities in the areas of air quality, water quality, control of toxic substances and hazardous and solid wastes. Applicable statutes and rules include the CAA, CWA, Nuclear Waste Act and CERCLA, among others. In many cases, regulations proposed by such authorities could have a significant impact on the Company's financial condition, results of operations and cash flows. In addition, the Company often cannot predict what conditions or requirements will be imposed by regulatory or legislative proposals. To the extent that compliance with environmental regulations or legislation results in capital expenditures or operating costs, the Company expects to recover such expenditures and costs through existing ratemaking provisions.

For the three years ended December 31, 2015, the Company's capital expenditures for environmental control equipment at its fossil fuel generating stations totaled $41.4 million. During this same period, the Company expended approximately $38.5 million for the construction and retirement of landfills and ash ponds, net of disposal proceeds. In addition, the Company made expenditures to operate and maintain environmental control equipment at its fossil plants of $8.7 million in 2015, $9.1 million in 2014 and $9.2 million in 2013, which are included in other operation and maintenance expense, and made expenditures to handle waste ash, net of disposal proceeds, of $1.3 million in 2015, $1.6 million in 2014 and $3.2 million in 2013, which are included in fuel used in electric generation. In addition, included within other operation and maintenance expense is an annual amortization of $1.4 million in each of 2015, 2014 and 2013 related to SCE&G's recovery of MGP remediation costs as approved by the SCPSC. It is not possible to estimate all future costs related to environmental matters, but forecasts for capitalized environmental expenditures for the Company are $15.3 million for 2016 and $88.9 million for the four-year period 2017-2020. These expenditures are included in the Company's Estimated Capital Expenditures table, are discussed in Liquidity and Capital Resources, and include known costs related to the matters discussed below.

The EPA is conducting an enforcement initiative against the utilities industry related to the NSR provisions and the NSPS of the CAA. As part of the initiative, many utilities have received requests for information under Section 114 of the CAA. In addition, the DOJ, on behalf of the EPA, has taken civil enforcement action against several utilities. The primary basis for these actions is the assertion by the EPA that maintenance activities undertaken by the utilities at their coal-fired power

plants constituted "major modifications" which required the installation of costly BACT. Some of the utilities subject to the actions have reached settlement. Though the Company cannot predict what action, if any, the EPA will initiate against it, any costs incurred are expected to be recoverable through rates.

plants constituted “major modifications” which required the installation of costly BACT. Some of the utilities subject to the actions have reached settlement. Though the Company cannot predict what action, if any, the EPA will initiate against it, any costs incurred are expected to be recoverable through rates.

With the pervasive emergence of concern over the issue of global climate change as a significant influence upon the economy, SCANA, SCE&G and GENCO are subject to climate-related financial risks, including those involving regulatory requirements responsive to GHG emissions, as well as those involving other potential physical impacts. Other business and financial risks arising from such climate change could also materialize. The Company cannot predict all of the climate-related regulatory and physical risks nor the related consequences which might impact the Company, and the following discussion should not be considered all-inclusive.

Physical effects associated with climate changes could include changes in weather patterns, such as storm frequency and intensity, and any resultant damage to the Company's electric system, as well as impacts on employees and customers and on the Company's supply chain and many others. Much of the service territory of SCE&G is subject to the damaging effects of Atlantic and Gulf coast hurricanes and also to the damaging impact of winter ice storms. To help mitigate the financial risks arising from these potential occurrences, SCE&G maintains insurance on certain properties. As part of its ongoing operations, SCE&G maintains emergency response and storm preparation plans and teams who receive ongoing training and related simulations, all in order to allow the Company to protect its assets and to return its systems to normal reliable operation in a timely fashion following any such event.

Environmental commitments and contingencies are further described in Note 10 to the consolidated financial statements.

REGULATORY MATTERS

SCANA and its subsidiaries are subject to the regulatory jurisdiction of the following entities for the matters noted.

Company	Regulatory Jurisdiction/Matters
SCANA	The SEC as to the issuance of certain securities and other matters and the FERC as to certain acquisitions and other matters.
SCANA and all subsidiaries	The CFTC, under Dodd-Frank, concerning recordkeeping, reporting, and other related regulations associated with swaps, options, forward contracts, and trade options, to the extent SCANA and any of its subsidiaries engage in any such activities.
SCE&G	The SEC as to the issuance of certain securities and other matters; the SCPSC as to retail electric and gas rates, service, accounting, issuance of securities (other than short-term borrowings) and other matters; the FERC as to issuance of short-term borrowings, guarantees of short-term indebtedness, certain acquisitions, wholesale electric power and transmission rates and services, and other matters; and the NRC with respect to the ownership, construction, operation and decommissioning of its currently operated and planned nuclear generating facilities. NRC jurisdiction encompasses broad supervisory and regulatory powers over the construction and operation of nuclear reactors, including matters of health and safety and environmental impact. In addition, the Federal Emergency Management Agency reviews, in conjunction with the NRC, certain aspects of emergency planning relating to the operation of nuclear plants.
SCE&G and GENCO	The FERC and DOE, under the Federal Power Act, as to the transmission of electric energy in interstate commerce, the wholesale sale of electric energy, the licensing of hydroelectric projects and certain other matters, including accounting.
GENCO	The SCPSC as to the issuance of securities (other than short-term borrowings) and the FERC as to issuance of short-term borrowings, the wholesale sale of electric energy, accounting, certain acquisitions and other matters.
Fuel Company	The SEC as to the issuance of certain securities.
PSNC Energy	The NCUC as to gas rates, service, issuance of securities (other than notes with a maturity of two years or less or renewals of notes with a maturity of six years or less), accounting and other matters, and the SEC as to the issuance of certain securities.

SCE&G and PSNC	The PHMSA and the DOT as to federal pipeline safety requirements for gas distribution pipeline systems and natural gas

SCE&G and PSNC Energy	The PHMSA and the DOT as to federal pipeline safety requirements for gas distribution pipeline systems and natural gas transmission systems, respectively. The ORS and the NCUC are responsible for enforcement of federal and state pipeline safety requirement in South Carolina (SCE&G) and North Carolina (PSNC Energy), respectively.
SCANA Energy	The GPSC through its certification as a natural gas marketer in Georgia and specifically as to retail prices for customers served under its regulated provider contract.

Material retail rate proceedings are described in Note 2 to the consolidated financial statements. In addition, the RSA allows natural gas distribution companies in South Carolina to request annual adjustments to rates to reflect changes in revenues and expenses and changes in investment. Such annual adjustments are subject to certain qualifying criteria and review by the SCPSC.

SCE&G's electric transmission system is subject to NERC, which develops and enforces reliability standards for the bulk power systems throughout North America. NERC is subject to oversight by FERC.

Dodd-Frank provides for substantial additional regulation of over-the-counter and security-based derivative instruments, among other things, and requires numerous rule-makings by the CFTC and the SEC to implement. The Company has determined that it meets the end-user exception in Dodd-Frank, with the lowest level of required regulatory reporting burden imposed by this law. The Company is currently complying with these enacted regulations and intends to comply with regulations enacted in the future, but cannot predict when the final regulations will be issued or what requirements they will impose.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

Following are descriptions of the Company's accounting policies and estimates which are most critical in terms of reporting financial condition or results of operations.

Accounting for Rate Regulated Operations

SCANA's regulated utilities record certain assets and liabilities that defer the recognition of expenses and revenues to future periods in accordance with accounting guidance for rate-regulated utilities. In the future, in the event of deregulation or other changes in the regulatory environment, the Company may no longer meet the criteria of accounting for rate-regulated utilities, and could be required to write off its regulatory assets and liabilities. Such an event could have a material effect on the results of operations, liquidity or financial position of the Company's Electric Operations and Gas Distribution segments in the period the write-off would be recorded. See Note 2 to the consolidated financial statements for a description of the Company's regulatory assets and liabilities.

The Company's generation assets would be exposed to considerable financial risks in a deregulated electric market. If market prices for electric generation do not produce adequate revenue streams and the enabling legislation or regulatory actions do not provide for recovery of the resulting stranded costs, the Company could be required to write down its investment in those assets. The Company cannot predict whether any write-downs would be necessary and, if they were, the extent to which they would affect the Company's results of operations in the period in which they would be recorded. As of December 31, 2015, the Company's net investments in fossil/hydro and nuclear generation assets were approximately $2.3 billion and $4.1 billion, respectively.

In the future, as a result of deregulation or other changes in the regulatory environment or changes in accounting requirements, the Company could also be required to write off its regulatory assets and liabilities. Such an event could have a material effect on the Company's results of operations, liquidity or financial position in the period the write-off would be recorded.

Revenue Recognition and Unbilled Revenues

Revenues related to the sale of energy are recorded when service is rendered or when energy is delivered to customers. Because customers of the Company's utilities and retail gas operations are billed on cycles which vary based on the timing of the actual reading of their electric and gas meters, the Company records estimates for unbilled revenues at the end of each reporting period. Such unbilled revenue amounts reflect estimates of the amount of energy delivered to customers for which they have not yet been billed. Such unbilled revenues reflect consideration of estimated usage by customer class, the effects of

different rate schedules and, where applicable, the impact of weather normalization or other regulatory provisions of rate structures. The accrual of unbilled revenues in this manner properly matches revenues and related costs. Accounts receivable included unbilled revenues of $129.1 million at December 31, 2015 and $186.4 million at December 31, 2014, compared to total revenues of $4.4 billion in 2015 and $5.0 billion in 2014.

different rate schedules and, where applicable, the impact of weather normalization or other regulatory provisions of rate structures. The accrual of unbilled revenues in this manner properly matches revenues and related costs. Accounts receivable included unbilled revenues of $129.1 million at December 31, 2015 and $186.4 million at December 31, 2014, compared to total revenues of $4.4 billion in 2015 and $5.0 billion in 2014.

Nuclear Decommissioning

Accounting for decommissioning costs for nuclear power plants involves significant estimates related to costs to be incurred many years into the future. Among the factors that could change SCE&G’s accounting estimates related to decommissioning costs are changes in technology, changes in regulatory and environmental remediation requirements, and changes in financial assumptions such as discount rates and the estimated timing of cash flows. Changes in any of these estimates could significantly impact the Company’s financial position and cash flows (although changes in such estimates should be earnings-neutral, because these costs are expected to be collected from ratepayers).

Based on a decommissioning cost study, SCE&G’s two-thirds share of estimated site-specific nuclear decommissioning costs for Summer Station Unit 1, including both the cost of decommissioning plant components that are and are not subject to radioactive contamination, totals $696.8 million, stated in 2012 dollars. Santee Cooper is responsible for decommissioning costs related to its one-third ownership interest in Summer Station Unit 1. The cost estimate assumes that upon closure the site would be maintained for 60 years in such a manner as to allow for subsequent decontamination that would permit release for unrestricted use.

Under SCE&G’s method of funding decommissioning costs, amounts collected through rates are invested in insurance policies on the lives of certain Company personnel. SCE&G transfers to an external trust fund the amounts collected through electric rates, insurance proceeds and interest thereon, less expenses. The trusteed asset balance reflects the net cash surrender value of the insurance policies and cash held by the trust. Management intends for the fund, including earnings thereon, to provide for all eventual decommissioning expenditures for Summer Station Unit 1 on an after-tax basis.

Asset Retirement Obligations

The Company accrues for the legal obligation associated with the retirement of long-lived tangible assets that result from the acquisition, construction, development and normal operation in accordance with applicable accounting guidance. The Company recognizes obligations at present value in the period in which they are incurred, and capitalizes associated asset retirement costs as a part of the carrying amount of the related long-lived assets. Because such obligations relate primarily to the Company’s regulated utility operations, their recognition has no significant impact on results of operations. As of December 31, 2015, the Company has recorded AROs of $176 million for nuclear plant decommissioning (as discussed above) and AROs of $344 million for other conditional obligations primarily related to generation, transmission and distribution properties, including gas pipelines. All of the amounts are based upon estimates which are subject to varying degrees of imprecision, particularly since payments in settlement of such obligations may be made many years in the future. Changes in these estimates will be recorded over time; however, these changes in estimates are not expected to materially impact results of operations so long as the regulatory framework for the utilities remains in place.

Accounting for Pensions and Other Postretirement Benefits

The Company recognizes the funded status of its defined benefit pension plan as an asset or liability and changes in funded status as a component of net periodic benefit cost or other comprehensive income, net of tax, or as a regulatory asset as required by accounting guidance. Accounting guidance requires the use of several assumptions that impact pension cost, of which the discount rate and the expected return on assets are the most sensitive. Net pension cost of $18.0 million recorded in 2015 reflects the use of a 4.20% discount rate derived using a cash flow matching technique, and an assumed 7.5% long-term rate of return on plan assets. The Company believes that these assumptions and the resulting pension cost amount were reasonable. For purposes of comparison, a 25 basis point reduction in the discount rate in 2015 would have increased the Company’s pension cost by $1.9 million and increased the pension obligation by $26.8 million. Further, had the assumed long-term rate of return on assets been 7.25%, the Company’s pension cost for 2015 would have increased by $2.1 million.

The following information with respect to pension assets (and returns thereon) should also be noted.

The Company determines the fair value of the majority of its pension assets utilizing market quotes or derives them from modeling techniques that incorporate market data. Less than 10% of assets are valued using less transparent Level 3 methods.

In developing the expected long-term rate of return assumptions, the Company evaluates historical performance, targeted allocation amounts and expected payment terms. As of the beginning of 2015, the plan’s historical 10, 15, 20 and 25 year cumulative performance showed actual returns of 6.0%, 5.4%, 8.7% and 8.8%, respectively. The 2015 expected long-term rate of return of 7.50% was based on a target asset allocation of 58% with equity managers, 33% with fixed income managers and 9% with hedge fund managers. Management regularly reviews such allocations and periodically rebalances the portfolio when considered appropriate. As of the beginning of 2016, the plan’s historical 10, 15, 20 and 25 year cumulative performance showed actual returns of 5.3%, 4.6%, 7.2% and 8.7%, respectively. For 2016, the expected rate of return is 7.50%.

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Pursuant to regulatory orders, certain previously deferred pension costs are being amortized as described in Note 2 to the consolidated financial statements. Current pension expense for electric operations is being recovered through a pension cost rider, and current pension expense related to SCE&G's gas operations is being recovered through cost of service rates.

Pension benefits are not offered to employees hired or rehired after December 31, 2013, and pension benefits for existing participants will no longer accrue for services performed or compensation earned after December 31, 2023. As a result, the significance of pension costs and the criticality of the related estimates to the Company's financial statements will continue to diminish. Further, the pension trust is adequately funded under current regulations, and management does not anticipate the need to make significant pension contributions for the foreseeable future.

The Company accounts for the cost of its postretirement medical and life insurance benefit plan in a similar manner to that used for its defined benefit pension plan. This plan is unfunded, so no assumptions related to rate of return on assets impact the net expense recorded; however, the selection of discount rates can significantly impact the actuarial determination of net expense. The Company used a discount rate of 4.30%, derived using a cash flow matching technique, and recorded a net cost of $19.2 million for 2015. Had the selected discount rate been 4.05% (25 basis points lower than the discount rate referenced above), the expense for 2015 would have been $0.8 million higher and increased the obligation by $9.5 million. Because the plan provisions include “caps” on company per capita costs, and because employees hired after December 31, 2010 are responsible for the full cost of retiree medical benefits elected by them, healthcare cost inflation rate assumptions do not materially impact the net expense recorded.

OTHER MATTERS

Off-Balance Sheet Arrangements

SCANA holds insignificant investments in securities and business ventures. SCANA does not engage in significant off-balance sheet financing or similar transactions, although it is party to incidental operating leases in the normal course of business, generally for office space, furniture, vehicles, equipment, airplanes and rail cars.

Claims and Litigation

For a description of claims and litigation see Note 10 to the consolidated financial statements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

All financial instruments described in this section are held for purposes other than trading.

Interest Rate Risk

The tables below provide information about long-term debt issued by the Company and other financial instruments that are sensitive to changes in interest rates. For debt obligations, the tables present principal cash flows and related weighted average interest rates by expected maturity dates. For interest rate swaps, the figures shown reflect notional amounts, weighted average interest rates and related maturities. Fair values for debt represent quoted market prices. Interest rate swap agreements are valued using discounted cash flow models with independently sourced data.

December 31, 2015	**Expected Maturity Date**							
Millions of dollars	**2016**	**2017**	**2018**	**2019**	**2020**	**Thereafter**	**Total**	**Fair Value**
Long-Term Debt:								
Fixed Rate ($)	111.5	10.6	719.8	9.1	358.3	4,673.0	5,882.3	6,336.2
Average Fixed Interest Rate (%)	1.16	4.42	6.02	4.73	6.35	5.63	5.63	—
Variable Rate ($)	4.4	4.4	4.4	4.4	4.4	129.4	151.4	145.5
Average Variable Interest Rate (%)	1.11	1.11	1.11	1.11	1.11	0.55	0.63	—

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Long-Term Debt:								
Fixed Rate ($)	111.5	10.6	719.8	9.1	358.3	4,673.0	5,882.3	6,336.2
Average Fixed Interest Rate (%)	1.16	4.42	6.02	4.73	6.35	5.63	5.63	—
Variable Rate ($)	4.4	4.4	4.4	4.4	4.4	129.4	151.4	145.5
Average Variable Interest Rate (%)	1.11	1.11	1.11	1.11	1.11	0.55	0.63	—
Interest Rate Swaps:								
Pay Fixed/Receive Variable ($)	654.4	554.4	4.4	4.4	4.4	133.0	1,355.0	(72.1)
Average Pay Interest Rate (%)	2.89	2.91	6.17	6.17	6.17	4.62	3.10	—
Average Receive Interest Rate (%)	0.62	0.62	1.11	1.11	1.11	0.52	0.61	—

December 31, 2014	**Expected Maturity Date**							
Millions of dollars	**2015**	**2016**	**2017**	**2018**	**2019**	**Thereafter**	**Total**	**Fair Value**
Long-Term Debt:								
Fixed Rate ($)	161.5	110.4	9.5	718.6	8.1	4,529.7	5,537.9	6,437.4
Average Fixed Interest Rate (%)	7.48	1.14	4.62	5.95	4.97	5.29	5.35	—
Variable Rate ($)	4.4	4.4	4.4	4.4	4.4	133.8	155.8	151.2
Average Variable Interest Rate (%)	0.92	0.92	0.92	0.92	0.92	0.48	0.54	—
Interest Rate Swaps:								
Pay Fixed/Receive Variable ($)	954.4	104.4	4.4	4.4	4.4	133.8	1,205.8	(256.7)
Average Pay Interest Rate (%)	3.84	3.74	6.17	6.17	6.17	4.70	3.95	—
Average Receive Interest Rate (%)	0.26	0.28	0.92	0.92	0.92	0.47	0.29	—

While a decrease in interest rates would increase the fair value of debt, it is unlikely that events which would result in a realized loss will occur.

For further discussion of the Company’s long-term debt and interest rate derivatives, see ITEM 7. MANAGEMENT’S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS — Liquidity and Capital Resources and Notes 4 and 6 to the consolidated financial statements.

Commodity Price Risk

The following table provides information about the Company’s financial instruments that are sensitive to changes in natural gas prices. Weighted average settlement prices are per 10,000 MMBTU. Fair value represents quoted market prices.

Expected Maturity	**2016**	**2017**	**2018**
Futures - Long			

Commodity Price Risk

The following table provides information about the Company's financial instruments that are sensitive to changes in natural gas prices. Weighted average settlement prices are per 10,000 MMBTU. Fair value represents quoted market prices.

Expected Maturity	**2016**	**2017**	**2018**
Futures - Long			
Settlement Price (a)	2.45	2.82	—
Contract Amount (b)	24.4	3.0	—
Fair Value (b)	21.4	2.9	—
Futures - Short			
Settlement Price (a)	2.49	—	—
Contract Amount (b)	1.7	—	—
Fair Value (b)	1.5	—	—
Options - Purchased Call (Long)			
Strike Price (a)	3.31	3.03	—
Contract Amount (b)	23.3	2.5	—
Fair Value (b)	0.5	0.2	—
Swaps - Commodity			
Pay fixed/receive variable (b)	52.1	9.5	4.5
Average pay rate (a)	3.2280	3.6810	3.8753
Average received rate (a)	2.4517	2.8000	2.9235
Fair Value (b)	39.6	7.2	3.4
Pay variable/receive fixed (b)	35.4	7.9	3.2
Average pay rate (a)	2.4705	2.7995	2.9240
Average received rate (a)	3.1645	3.5821	3.9355
Fair Value (b)	45.4	10.1	4.3
Swaps - Basis			
Pay variable/receive variable (b)	3.9	0.7	—
Average pay rate (a)	2.4630	2.8231	—
Average received rate (a)	2.4432	2.8281	—
Fair Value (b)	3.9	0.7	—

(a) Weighted average, in dollars
(b) Millions of dollars

The Company uses derivative instruments to hedge forward purchases and sales of natural gas, which create market risks of different types. See Note 6 to the consolidated financial statements. The information above includes those financial positions of Energy Marketing and PSNC Energy.

PSNC Energy utilizes futures, options and swaps to hedge gas purchasing activities. PSNC Energy's tariffs include a provision for the recovery of actual gas costs incurred. PSNC Energy defers premiums, transaction fees, margin requirements and any realized gains or losses from its hedging program for subsequent recovery from customers.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
SCANA Corporation
Cayce, South Carolina

We have audited the accompanying consolidated balance sheets of SCANA Corporation and subsidiaries (the "Company") as of December 31, 2015 and 2014, and the related consolidated statements of income, comprehensive income, cash flows, and changes in common equity for each of the three years in the period ended December 31, 2015. Our audits also included the financial statement schedule listed in Part IV at Item 15. These financial statements and the financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements and financial statement schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2015 and 2014, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2015, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2015, based on the criteria established in *Internal Control-Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 26, 2016 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/DELOITTE & TOUCHE LLP
Charlotte, North Carolina
February 26, 2016

SCANA Corporation and Subsidiaries
Consolidated Balance Sheets

December 31, (Millions of dollars)	2015	2014
Assets		
Utility Plant In Service	$ 12,883	$ 12,289
Accumulated Depreciation and Amortization	(4,307)	(4,088)
Construction Work in Progress	4,051	3,323
Plant to be Retired, Net	—	169
Nuclear Fuel, Net of Accumulated Amortization	308	329
Goodwill	210	210
Utility Plant, Net	13,145	12,232
Nonutility Property and Investments:		
Nonutility property, net of accumulated depreciation of $124 and $122	280	284
Assets held in trust, net-nuclear decommissioning	115	113
Other investments	71	75

SCANA Corporation and Subsidiaries
Consolidated Balance Sheets

December 31, (Millions of dollars)	2015	2014
Assets		
Utility Plant In Service	$ 12,883	$ 12,289
Accumulated Depreciation and Amortization	(4,307)	(4,088)
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Goodwill	210	210
Utility Plant, Net	13,145	12,232
Nonutility Property and Investments:		
Nonutility property, net of accumulated depreciation of $124 and $122	280	284
Assets held in trust, net-nuclear decommissioning	115	113
Other investments	71	75
Nonutility Property and Investments, Net	466	472
Current Assets:		
Cash and cash equivalents	176	137
Receivables:		
Customer, net of allowance for uncollectible accounts of $5 and $7	505	684
Other	227	154
Inventories:		
Fuel	164	222
Materials and supplies	148	139
Prepayments	115	320
Other current assets	43	148
Assets held for sale	—	341
Total Current Assets	1,378	2,145
Deferred Debits and Other Assets:		
Regulatory assets	1,937	1,823
Other	220	146
Total Deferred Debits and Other Assets	2,157	1,969
Total	$ 17,146	$ 16,818

See Notes to Consolidated Financial Statements.

December 31, (Millions of dollars)	2015	2014
Capitalization and Liabilities		
Common Stock - no par value (shares outstanding: December 31, 2015 - 142.9 million; December 31, 2014 - 142.7 million)	$ 2,390	$ 2,378
Retained Earnings	3,118	2,684

December 31, (Millions of dollars)	2015	2014
Capitalization and Liabilities		
Common Stock - no par value (shares outstanding: December 31, 2015 - 142.9 million; December 31, 2014 - 142.7 million)	$ 2,390	$ 2,378
Retained Earnings	3,118	2,684
Accumulated Other Comprehensive Loss	(65)	(75)
Total Common Equity	5,443	4,987
Long-Term Debt, Net	5,882	5,497
Total Capitalization	11,325	10,484
Current Liabilities:		
Short-term borrowings	531	918
Current portion of long-term debt	116	166
Accounts payable	590	520
Customer deposits and customer prepayments	137	98
Taxes accrued	242	182
Interest accrued	83	83
Dividends declared	76	73
Liabilities held for sale	—	52
Derivative financial instruments	50	233
Other	127	143
Total Current Liabilities	1,952	2,468
Deferred Credits and Other Liabilities:		
Deferred income taxes, net	1,907	1,931
Asset retirement obligations	520	563
Pension and postretirement benefits	315	315
Regulatory liabilities	855	814
Other	272	243
Total Deferred Credits and Other Liabilities	3,869	3,866
Commitments and Contingencies (Note 10)	—	—
Total	$ 17,146	$ 16,818

See Notes to Consolidated Financial Statements.

SCANA Corporation and Subsidiaries
Consolidated Statements of Income

Years Ended December 31, (Millions of dollars, except per share amounts)	2015	2014	2013
Operating Revenues:			
Electric	$ 2,551	$ 2,622	$ 2,423
Gas-regulated	811	1,028	955
Gas-nonregulated	1,018	1,301	1,117
Total Operating Revenues	4,380	4,951	4,495
Operating Expenses:			

SCANA Corporation and Subsidiaries
Consolidated Statements of Income

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Gas-regulated	811	1,028	955
Gas-nonregulated	1,018	1,301	1,117
Total Operating Revenues	4,380	4,951	4,495
Operating Expenses:			
Fuel used in electric generation	660	793	745
Purchased power	52	81	43
Gas purchased for resale	1,287	1,729	1,491
Other operation and maintenance	715	728	708
Depreciation and amortization	358	384	378
Other taxes	234	229	220
Total Operating Expenses	3,306	3,944	3,585
Gain on sale of CGT, net of transaction costs	234	—	—
Operating Income	1,308	1,007	910
Other Income (Expense):			
Other income	75	122	100
Other expenses	(60)	(64)	(46)
Gain on sale of SCI, net of transaction costs	107	—	—
Interest charges, net of allowance for borrowed funds used during construction of $15, $16 and $14	(318)	(312)	(297)
Allowance for equity funds used during construction	27	33	27
Total Other Expense	(169)	(221)	(216)
Income Before Income Tax Expense	1,139	786	694
Income Tax Expense	393	248	223
Net Income	$ 746	$ 538	$ 471
Per Common Share Data			
Basic Earnings Per Share of Common Stock	$ 5.22	$ 3.79	$ 3.40
Diluted Earnings Per Share of Common Stock	5.22	3.79	3.39
Weighted Average Common Shares Outstanding (millions)			
Basic	142.9	141.9	138.7
Diluted	142.9	141.9	139.1
Dividends Declared Per Share of Common Stock	$ 2.18	$ 2.10	$ 2.03

See Notes to Consolidated Financial Statements.

SCANA Corporation and Subsidiaries
Consolidated Statements of Comprehensive Income

Years Ended December 31, (Millions of dollars)	2015	2014	2013
Net Income	$ 746	$ 538	$ 471
Other Comprehensive Income (Loss), net of tax:			
Unrealized Losses on Cash Flow Hedging Activities:			
Unrealized gains (losses) on cash flow hedging activities arising during period, net of tax of $(7), $(9) and $4	(12)	(14)	7
Gains (losses) on cash flow hedging activities reclassified to interest expense, net of tax of $4, $4 and $5	7	7	8
Gains (losses) on cash flow hedging activities reclassified to gas purchased for resale, net of tax of $9, $(2) and $2	15	(4)	3
Net unrealized gains (losses) on cash flow hedging activities	10	(11)	18
Deferred Costs of Employee Benefit Plans:			
Deferred costs of employee benefit plans, net of tax of $-, $(3) and $4	—	(5)	7
Amortization of deferred employee benefit plan costs reclassified to net income (see Note 8), net of tax of $-, $- and $-	—	1	1
Net deferred costs of employee benefit plans	—	(4)	8
Other Comprehensive Income (Loss)	10	(15)	26
Total Comprehensive Income	$ 756	$ 523	$ 497

See Notes to Consolidated Financial Statements.

SCANA Corporation and Subsidiaries
Consolidated Statements of Cash Flows

For the Years Ended December 31, (Millions of dollars)	2015	2014	2013
Cash Flows From Operating Activities:			
Net Income	$ 746	$ 538	$ 471
Adjustments to reconcile net income to net cash provided from operating activities:			
Gain on sale of subsidiaries	(355)	—	—
Losses from equity method investments	3	5	7
Deferred income taxes, net	(31)	235	49
Depreciation and amortization	368	403	393
Amortization of nuclear fuel	46	45	57
Allowance for equity funds used during construction	(27)	(33)	(27)
Carrying cost recovery	(12)	(9)	(3)
Changes in certain assets and liabilities:			
Receivables	188	(33)	(38)
Inventories	(16)	(62)	21
Prepayments	211	(235)	49
Regulatory assets	148	(372)	113
Regulatory liabilities	3	(133)	56
Accounts payable	(78)	36	24
Taxes accrued	61	(24)	42

SCANA Corporation and Subsidiaries
Consolidated Statements of Cash Flows

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Inventories	(16)	(62)	21
Prepayments	211	(235)	49
Regulatory assets	148	(372)	113
Regulatory liabilities	3	(133)	56
Accounts payable	(78)	36	24
Taxes accrued	61	(24)	42
Pension and other postretirement benefits	(6)	133	(217)
Derivative financial instruments	(183)	225	(72)
Other assets	(21)	(8)	17
Other liabilities	14	19	108
Net Cash Provided From Operating Activities	1,059	730	1,050
Cash Flows From Investing Activities:			
Property additions and construction expenditures	(1,153)	(1,092)	(1,106)
Proceeds from sale of subsidiaries	647	—	—
Proceeds from investments (including derivative collateral returned)	1,117	347	222
Purchase of investments (including derivative collateral posted)	(1,018)	(475)	(176)
Payments upon interest rate derivative contract settlement	(263)	(95)	(49)
Proceeds from interest rate derivative contract settlement	10	—	163
Net Cash Used For Investing Activities	(660)	(1,315)	(946)
Cash Flows From Financing Activities:			
Proceeds from issuance of common stock	14	98	295
Proceeds from issuance of long-term debt	491	294	451
Repayments of long-term debt	(166)	(54)	(258)
Dividends	(309)	(294)	(281)
Short-term borrowings, net	(387)	542	(247)
Deferred financing costs	(3)	—	—
Net Cash Provided From (Used For) Financing Activities	(360)	586	(40)
Net Increase in Cash and Cash Equivalents	39	1	64
Cash and Cash Equivalents, January 1	137	136	72
Cash and Cash Equivalents, December 31	$ 176	$ 137	$ 136
Supplemental Cash Flow Information:			

Cash paid for—Interest (net of capitalized interest of $15, $16 and $14)	$ 306	$ 301	$ 288
—Income taxes	184	299	104
Noncash Investing and Financing Activities:			
Accrued construction expenditures	244	180	111
Capital leases	6	5	6
Nuclear fuel purchase	—	—	98

See Notes to Consolidated Financial Statements.

SCANA Corporation and Subsidiaries
Consolidated Statements of Changes in Common Equity

	Common Stock				Accumulated Other Comprehensive Income (Loss)			
Millions	**Shares**	**Outstanding Amount**	**Treasury Shares**	**Retained Earnings**	**Gains (Losses) Cash Flow Hedges**	**Deferred Employee Benefit Plans**	**Total AOCI**	**Total**
Balance as of January 1, 2013	132	$ 1,992	$ (9)	$ 2,257	$ (70)	$ (16)	$ (86)	$ 4,154
Net Income				471				471
Other Comprehensive Income (Loss)								
Losses arising during the period					7	7	14	14
Losses/amortization reclassified from AOCI					11	1	12	12
Total Comprehensive Income (Loss)				471	18	8	26	497
Issuance of Common Stock	9	297						297
Dividends Declared				(284)				(284)
Balance as of December 31, 2013	141	2,289	(9)	2,444	(52)	(8)	(60)	4,664
Net Income				538				538
Other Comprehensive Income (Loss)								
Losses arising during the period					(14)	(5)	(19)	(19)
Losses/amortization reclassified from AOCI					3	1	4	4
Total Comprehensive Income (Loss)				538	(11)	(4)	(15)	523
Issuance of Common Stock	2	99	(1)					98
Dividends Declared				(298)				(298)
Balance as of December 31, 2014	143	2,388	(10)	2,684	(63)	(12)	(75)	4,987
Net Income				746				746
Other Comprehensive Income (Loss)								
Losses arising during the period					(12)	—	(12)	(12)
Losses/amortization reclassified from AOCI					22	—	22	22
Total Comprehensive Income (Loss)				746	10	—	10	756
Issuance of Common Stock	—	14	(2)					12
Dividends Declared				(312)				(312)
Balance as of December 31, 2015	143	$ 2,402	$ (12)	$ 3,118	$ (53)	$ (12)	$ (65)	$ 5,443

Dividends declared per share of common stock were $2.18, $2.10 and $2.03 for 2015, 2014 and 2013, respectively.

See Notes to Consolidated Financial Statements.

Notes to Consolidated Financial Statements

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Organization and Principles of Consolidation

SCANA, a South Carolina corporation, is a holding company. The Company engages predominantly in the generation and sale of electricity to wholesale and retail customers in South Carolina, the purchase, sale and transportation of natural gas to wholesale and retail customers in South Carolina, North Carolina and Georgia and conducts other energy-related business.

The accompanying consolidated financial statements reflect the accounts of SCANA, the following wholly-owned subsidiaries, and subsidiaries that formerly were wholly-owned during the periods presented.

Regulated businesses	Nonregulated businesses
South Carolina Electric & Gas Company	SCANA Energy Marketing, Inc.
South Carolina Fuel Company, Inc.	ServiceCare, Inc.
South Carolina Generating Company, Inc.	SCANA Services, Inc.
Public Service Company of North Carolina, Incorporated	SCANA Corporate Security Services, Inc.

CGT and SCI were sold in the first quarter of 2015. Accordingly, the assets and liabilities of these entities are aggregated and shown as Assets held for sale and Liabilities held for sale in the December 31, 2014 consolidated balance sheet. See Note 13.

The Company reports certain investments using the cost or equity method of accounting, as appropriate. Intercompany balances and transactions have been eliminated in consolidation, with the exception of profits on intercompany sales to regulated affiliates if the sales price is reasonable and the future recovery of the sales price through the rate-making process is probable, as permitted by accounting guidance.

Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amount of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Reclassifications

In April 2015, the FASB issued accounting guidance intended to simplify the presentation of debt issuance costs by requiring that such costs be deducted from carrying amounts related to debt when presented in the balance sheet. As permitted, the Company adopted this guidance retrospectively in the fourth quarter of 2015. As a result, for 2014 $34 million of unamortized debt issuance costs were reclassified to long-term debt, and certain amounts in Note 4 and Note 12 were also reclassified for comparative periods. The effect of adoption on the Company’s results of operations and cash flows was not significant.

In November 2015, the FASB issued accounting guidance intended to simplify the presentation of deferred tax assets and deferred tax liabilities by netting and classifying them as noncurrent on the statement of financial position. As permitted, the Company early adopted this guidance retrospectively in the fourth quarter of 2015. As a result, for 2014 $65.5 million of net deferred tax liabilities previously classified in current liabilities were reclassified to long-term liabilities. The effect of adoption on the Company's results of operations and cash flows was not significant.

Utility Plant

Utility plant is stated at original cost. The costs of additions, replacements and betterments to utility plant, including direct labor, material and indirect charges for engineering, supervision and AFC, are added to utility plant accounts. The original cost of utility property retired or otherwise disposed of is removed from utility plant accounts and generally charged to accumulated depreciation. The costs of repairs and replacements of items of property determined to be less than a unit of property or that do not increase the asset’s life or functionality are charged to expense.

AFC is a noncash item that reflects the period cost of capital devoted to plant under construction. This accounting practice results in the inclusion of, as a component of construction cost, the costs of debt and equity capital dedicated to construction investment. AFC is included in rate base investment and depreciated as a component of plant cost in establishing rates for utility services. The Company’s regulated subsidiaries calculated AFC using average composite rates of 6.1% for 2015, 7.2% for 2014 and 6.9% for 2013. These rates do not exceed the maximum rates

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The Company records provisions for depreciation and amortization using the straight-line method based on the estimated service lives of the various classes of property. In 2015, SCE&G adopted lower depreciation rates for electric and common plant, as approved by the SCPSC and further described in Note 2. In addition, CGT was sold in the first quarter of 2015 (see Note 13) and excluded from the 2015 calculation of composite weighted average depreciation rates. The composite weighted average depreciation rates for utility plant assets were as follows:

	2015	2014	2013
SCE&G	2.55%	2.85%	2.96%
GENCO	2.66%	2.66%	2.66%
CGT	—	2.11%	2.19%
PSNC Energy	2.94%	2.98%	3.01%
Weighted average of above	2.61%	2.84%	2.93%

SCE&G records nuclear fuel amortization using the units-of-production method. Nuclear fuel amortization is included in “Fuel used in electric generation” and recovered through the fuel cost component of retail electric rates. Provisions for amortization of nuclear fuel include amounts necessary to satisfy obligations to the DOE under a contract for disposal of spent nuclear fuel.

Jointly Owned Utility Plant

SCE&G jointly owns and is the operator of Summer Station Unit 1. In addition, SCE&G will jointly own and will be the operator of the New Units being designed and constructed at the site of Summer Station. Each joint owner provides its own financing and shares the direct expenses and generation output in proportion to its ownership of a unit. SCE&G’s share of the direct expenses is included in the corresponding operating expenses on its income statement.

As of December 31,	**2015**		**2014**	
	Unit 1	**New Units**	**Unit 1**	**New Units**
Percent owned	66.7%	55.0%	66.7%	55.0%
Plant in service	$ 1.2 billion	—	$ 1.2 billion	—
Accumulated depreciation	$ 620.4 million	—	$ 578.3 million	—
Construction work in progress	$ 214.6 million	$ 3.4 billion	$ 199.3 million	$ 2.7 billion

For a discussion of expected cash outlays and expected in-service dates for the New Units and a description of SCE&G's agreement to acquire an additional 5% ownership in the New Units, see Note 10.

Included within other receivables on the balance sheet were amounts due to SCE&G from Santee Cooper for its share of direct expenses and construction costs for Summer Station Unit 1 and the New Units. These amounts totaled $178.8 million at December 31, 2015 and $88.9 million at December 31, 2014.

Plant to be Retired

At December 31, 2014, SCE&G expected to retire three units that are or were coal-fired by 2020, which was prior to the end of the previously estimated useful lives over which the units were being depreciated. As such, these units were identified as Plant to be Retired. Subsequently, these units were converted to be gas-fired. In the third quarter of 2015, in connection with the adoption of a customary depreciation study and related analysis (see Note 2), SCE&G determined that these units would not likely be retired by 2020, and their depreciation rates were set to recover the units' net carrying value over their respective revised useful lives. Accordingly, the net carrying value of these units is no longer classified as Plant to be Retired at December 31, 2015.

Major Maintenance

Planned major maintenance costs related to certain fossil fuel turbine equipment and nuclear refueling outages are accrued in periods other

Major Maintenance

Planned major maintenance costs related to certain fossil fuel turbine equipment and nuclear refueling outages are accrued in periods other than when incurred in accordance with approval by the SCPSC for such accounting treatment and rate recovery of expenses accrued thereunder. The difference between such cumulative major maintenance costs and cumulative collections is classified as a regulatory asset or regulatory liability on the consolidated balance sheet. Other planned major maintenance is expensed when incurred.

Through 2017, SCE&G is authorized to collect $18.4 million annually through electric rates to offset certain turbine maintenance expenditures. For the years ended December 31, 2015 and 2014, SCE&G incurred $16.5 million and $19.4 million, respectively, for turbine maintenance.

Nuclear refueling outages are scheduled 18 months apart. As approved by the SCPSC, effective January 1, 2013, SCE&G accrues $1.4 million per month for its portion of the nuclear refueling outages that are scheduled for the spring of 2014 through the spring of 2020. Total costs for 2014 were $43.7 million, of which SCE&G was responsible for $29.1 million. Total costs for 2015 were $40.2 million, of which SCE&G was responsible for $26.8 million.

Goodwill

The Company considers certain amounts categorized by FERC as “acquisition adjustments” to be goodwill. For each period presented, assets with a carrying value of $210 million (net of a writedown taken in 2002 of $230 million) for PSNC Energy (Gas Distribution segment) were classified as goodwill. The Company tests goodwill for impairment annually as of January 1, unless indicators, events or circumstances require interim testing to be performed. The goodwill impairment testing is generally a two-step quantitative process which in step one requires estimation of the fair value of the reporting unit and the comparison of that amount to its carrying value. If this step indicates an impairment (a carrying value in excess of fair value), then step two, measurement of the amount of the goodwill impairment (if any), is required. Accounting guidance adopted by the Company gives it the option to first perform a qualitative assessment of impairment. Based on this qualitative ("step zero") assessment, if the Company determines that it is not more likely than not that the fair value of a reporting unit is less than its carrying amount, the Company is not required to proceed with the two-step quantitative assessment.

In evaluations of PSNC Energy, fair value was estimated using the assistance of an independent appraisal. In evaluations for the periods presented, step one has indicated no impairment, and no impairment charges have been recorded. Should a write-down be required in the future, such a charge would be treated as an operating expense.

Nuclear Decommissioning

Based on a decommissioning cost study, SCE&G’s two-thirds share of estimated site-specific nuclear decommissioning costs for Summer Station Unit 1, including the cost of decommissioning plant components both subject to and not subject to radioactive contamination, totals $696.8 million, stated in 2012 dollars. Santee Cooper is responsible for decommissioning costs related to its one-third ownership interest in Summer Station Unit 1. The cost estimate assumes that the site will be maintained over a period of approximately 60 years in such a manner as to allow for subsequent decontamination that would permit release for unrestricted use.

Under SCE&G’s method of funding decommissioning costs, amounts collected through rates ($3.2 million pre-tax in each period presented) are invested in insurance policies on the lives of certain Company personnel. SCE&G transfers to an external trust fund the amounts collected through electric rates, insurance proceeds and interest thereon, less expenses. The trusteed asset balance reflects the net cash surrender value of the insurance policies and cash held by the trust. Management intends for the fund, including earnings thereon, to provide for all eventual decommissioning expenditures for Summer Station Unit 1 on an after-tax basis.

Cash and Cash Equivalents

The Company considers temporary cash investments having original maturities of three months or less at time of purchase to be cash equivalents. These cash equivalents are generally in the form of commercial paper, certificates of deposit, repurchase agreements and treasury bills.

Receivables

Customer receivables reflect amounts due from customers arising from the delivery of energy or related services and include both billed and unbilled amounts earned pursuant to revenue recognition practices described below. Customer receivables are generally due within one month of receipt of invoices which are presented on a monthly cycle basis.

Other receivables consist primarily of amounts due from Santee Cooper related to the construction and operation of jointly owned nuclear generating facilities at Summer Station.

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Inventories

Materials and supplies include the average cost of transmission, distribution, and generating plant materials. Materials are charged to inventory when purchased and then expensed or capitalized to plant, as appropriate, at weighted average cost when used. Fuel inventory includes the average cost of coal, natural gas, fuel oil and emission allowances. Fuel is charged to inventory when purchased and is expensed, at weighted average cost, as used and recovered through fuel cost recovery rates approved by the SCPSC or NCUC, as applicable.

Asset Management and Supply Service Agreements

PSNC Energy utilizes asset management and supply service agreements with counterparties for certain natural gas storage facilities. Such counterparties held 46% and 48% of PSNC Energy's natural gas inventory at December 31, 2015 and December 31, 2014, respectively, with a carrying value of $17.7 million and $26.1 million, respectively, through either capacity release or agency relationships. Under the terms of the asset management agreements, PSNC Energy receives storage asset management fees. No fees are received under supply service agreements. The agreements expire March 31, 2017.

Income Taxes

The Company files consolidated federal income tax returns. Under a joint consolidated income tax allocation agreement, each subsidiary's current and deferred tax expense is computed on a stand-alone basis. Deferred tax assets and liabilities are recorded for the tax effects of all significant temporary differences between the book basis and tax basis of assets and liabilities at currently enacted tax rates. Deferred tax assets and liabilities are adjusted for changes in such tax rates through charges or credits to regulatory assets or liabilities if they are expected to be recovered from, or passed through to, customers of the Company's regulated subsidiaries; otherwise, they are charged or credited to income tax expense.

Regulatory Assets and Regulatory Liabilities

The Company's rate-regulated utilities record costs that have been or are expected to be allowed in the ratemaking process in a period different from the period in which the costs would be charged to expense or record revenue in a period different from the period in which the revenue would be recorded by a nonregulated enterprise. These expenses deferred for future recovery from customers or obligations to be refunded to customers are primarily classified in the balance sheet as regulatory assets and regulatory liabilities (see Note 2) and are amortized consistent with the treatment of the related costs or revenues in the ratemaking process. Deferred amounts expected to be recovered or repaid within 12 months are classified in the balance sheet as receivables or accounts payable, respectively.

Debt Issuance Premiums, Discounts and Other Costs

The Company presents long-term debt premiums, discounts and debt issuance costs within long-term debt and amortizes them as components of interest charges over the terms of the respective debt issues. For regulated subsidiaries, gains or losses on reacquired debt that is refinanced are recorded in other deferred debits or credits and are amortized over the term of the replacement debt, also as interest charges.

Environmental

The Company maintains an environmental assessment program to identify and evaluate current and former operations sites that could require environmental clean-up. As site assessments are initiated, estimates are made of the amount of expenditures, if any, deemed necessary to investigate and remediate each site. Environmental remediation liabilities are accrued when the criteria for loss contingencies are met. These estimates are refined as additional information becomes available; therefore, actual expenditures could differ significantly from the original estimates. Probable and estimable costs are accrued related to environmental sites on an undiscounted basis. Amounts estimated and accrued to date for site assessments and clean-

up relate solely to regulated operations. Amounts expected to be recovered through rates are recorded in regulatory assets and, if applicable, amortized over approved amortization periods. Other environmental costs are expensed as incurred.

Income Statement Presentation

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Income Statement Presentation

The Company presents the revenues and expenses of its regulated businesses and its retail natural gas marketing businesses (including those activities of segments described in Note 12) within operating income, and it presents all other activities within other income (expense). Consistent with this presentation, the gain on the sale of CGT is reflected within operating income and the gain on the sale of SCI is reflected within other income (expense).

Revenue Recognition

The Company records revenues during the accounting period in which it provides services to customers and includes estimated amounts for electricity and natural gas delivered but not billed. Unbilled revenues totaled $129.1 million at December 31, 2015 and $186.4 million at December 31, 2014.

Fuel costs, emission allowances and certain environmental reagent costs for electric generation are collected through the fuel cost component in retail electric rates. The SCPSC establishes this component during fuel cost hearings. Any difference between actual fuel costs and amounts contained in the fuel cost component is adjusted through revenue and is deferred and included when determining the fuel cost component during subsequent hearings.

SCE&G customers subject to a PGA are billed based on a cost of gas factor calculated in accordance with a gas cost recovery procedure approved by the SCPSC and subject to adjustment monthly. Any difference between actual gas costs and amounts contained in rates is adjusted through revenue and is deferred and included when making the next adjustment to the cost of gas factor. PSNC Energy’s PGA mechanism authorized by the NCUC allows the recovery of all prudently incurred gas costs, including the results of its hedging program, from customers. Any difference between actual gas costs and amounts contained in rates is deferred and included when establishing gas costs during subsequent PGA filings or in annual prudence reviews.

SCE&G’s gas rate schedules for residential, small commercial and small industrial customers include a WNA which minimizes fluctuations in gas revenues due to abnormal weather conditions. An eWNA for SCE&G's electric customers was discontinued effective with the first billing cycle of 2014 as approved by the SCPSC.

PSNC Energy is authorized by the NCUC to utilize a CUT which allows it to adjust base rates semi-annually for residential and commercial customers based on average per customer consumption, whether impacted by weather or other factors.

Taxes that are billed to and collected from customers are recorded as liabilities until they are remitted to the respective taxing authority. Such taxes are not included in revenues or expenses in the statements of income.

Earnings Per Share

The Company computes basic earnings per share by dividing net income by the weighted average number of common shares outstanding for the period. The Company computes diluted earnings per share using this same formula, after giving effect to securities considered to be dilutive potential common stock utilizing the treasury stock method.

The weighted average number of common shares for each period presented for basic and diluted earnings per share purposes were identical, except that for 2013, the net effect of equity forward contracts resulted in such shares for diluted earnings per share purposes being 0.4 million higher than for basic earnings per share purposes.

New Accounting Matters

In April 2014, the FASB issued accounting guidance for reporting discontinued operations and disclosures of disposals of components of an entity. Under this guidance, only those discontinued operations which represent a strategic shift that will have a major effect on an entity’s operations and financial results should be reported as discontinued operations in the financial statements. As permitted, the Company adopted this guidance for the period ended December 31, 2014.

In May 2014, the FASB issued accounting guidance for revenue arising from contracts with customers that supersedes most current revenue recognition guidance, including industry-specific guidance. This revenue recognition model provides a five-step analysis in determining

In May 2014, the FASB issued accounting guidance for revenue arising from contracts with customers that supersedes most current revenue recognition guidance, including industry-specific guidance. This revenue recognition model provides a five-step analysis in determining when and how revenue is recognized, and will require revenue recognition to depict the transfer of promised goods or services to customers in an amount that reflects the consideration a company expects to receive in exchange for those goods or services. The Company is required to adopt this guidance in the first quarter of 2018 and early adoption is permitted in the first quarter of 2017. Adoption using a retrospective method is required, with options to elect certain practical expedients or to recognize a cumulative effect in the year of initial adoption. The Company has not determined when it will adopt this guidance or what elections it will make. The Company has not determined the impact this guidance will have on its results of operations, cash flows or financial position.

In April 2015, the FASB issued accounting guidance related to fees paid by a customer in a cloud computing arrangement. Among other things, the guidance clarifies how to account for a software license element included in a cloud computing arrangement, and makes explicit that a cloud computing arrangement not containing a software license element should be accounted for as a service contract. The Company has determined that this guidance, when adopted in the first quarter of 2016, will not significantly impact the Company’s results of operations, cash flows or financial position.

In July 2015, the FASB issued accounting guidance intended to simplify the subsequent measurement of inventory cost by requiring most inventory to be measured at the lower of cost and net realizable value. The Company expects to adopt this guidance when required in the first quarter of 2017. The Company is evaluating this guidance and has not determined what impact it will have on its results of operations, cash flows or financial position.

In January 2016, the FASB issued accounting guidance intended to clarify the classification and measurement of financial instruments and financial liabilities, among other things. The Company expects to adopt this guidance when required in the first quarter of 2018. The Company is evaluating this guidance and has not determined what impact it will have on its results of operations, cash flows or financial position.

In February 2016, the FASB issued accounting guidance related to the recognition, measurement and presentation of leases. The guidance applies a right-of-use model and, for lessees, requires all leases with a duration over twelve months to be recorded on the balance sheet, with the rights of use treated as assets and the payment obligations treated as liabilities. Further, and without consideration of any regulatory accounting requirements which may apply, depending primarily of the nature of the assets and the relative consumption of them, lease costs will be recognized either through the separate amortization of the right-of-use asset and the recognition of the interest cost related to the payment obligation, or through the recording of a combined straight-line rental expense. For lessors, the guidance calls for the recognition of income either through the derecognition of assets and subsequent recording of interest income on lease amounts receivable, or through the recognition of rental income on a straight line basis, also depending on the nature of the assets and relative consumption. The guidance will be effective for years beginning in 2019. The Company has not determined what impact this guidance will have on its results of operations, cash flows or financial position.

2. RATE AND OTHER REGULATORY MATTERS

Rate Matters

<u>Electric - Cost of Fuel</u>

SCE&G's retail electric rates include a cost of fuel component approved by the SCPSC which may be adjusted periodically to reflect changes in the price of fuel purchased by SCE&G.

Pursuant to a November 2013 SCPSC accounting order, the Company's electric revenue for 2013 was reduced for adjustments to the fuel cost component and related under-collected fuel balance of $41.6 million. Such adjustments are fully offset by the recognition within other income, also pursuant to that accounting order, of gains realized upon the settlement of certain interest rate derivatives which had been entered into in anticipation of the issuance of long-term debt, which gains had been deferred as a regulatory liability. See also Note 6.

Pursuant to an April 2014 SCPSC order, SCE&G increased its base fuel cost component by approximately $10.3 million for the 12-month period beginning with the first billing cycle of May 2014. The base fuel cost increase was offset by a reduction in SCE&G's rate rider related to pension costs approved by the SCPSC in March 2014. In addition, pursuant to the April 2014 order, electric revenue for 2014 was reduced by approximately $46 million for adjustments to the fuel cost component and related under-collected fuel balance. Such adjustments are fully offset by the recognition within other income of gains realized from the late 2013 settlement of certain interest rate derivatives which had been entered into in anticipation of the

issuance of long-term debt, which gains had been deferred as a regulatory liability. The order also provided for the accrual of certain debt-related carrying costs on its under-collected balance of base fuel costs from May 1, 2014 through April 30, 2015.

The cost of fuel includes amounts paid by SCE&G pursuant to the Nuclear Waste Act for the disposal of spent nuclear fuel. As a result of a November 2013 decision by the Court of Appeals, the DOE set the Nuclear Waste Act fee to zero effective May 16, 2014. The impact of changes issuance of long-term debt, which gains had been deferred as a regulatory liability. The order also provided for the accrual of certain debt-related carrying costs on its under-collected balance of base fuel costs from May 1, 2014 through April 30, 2015.

The cost of fuel includes amounts paid by SCE&G pursuant to the Nuclear Waste Act for the disposal of spent nuclear fuel. As a result of a November 2013 decision by the Court of Appeals, the DOE set the Nuclear Waste Act fee to zero effective May 16, 2014. The impact of changes to the Nuclear Waste Act fee is considered during annual fuel rate proceedings.

By order dated April 30, 2015, the SCPSC approved a settlement agreement among SCE&G and certain other parties in which SCE&G agreed to decrease the total fuel cost component of retail electric rates. Under this order, SCE&G is to recover an amount equal to its under-collected balance of base fuel and variable environmental costs as of April 30, 2015, over the subsequent 12-month period beginning with the first billing cycle of May 2015.

By order dated July 15, 2015, the SCPSC approved a settlement agreement among SCE&G and certain other parties concerning SCE&G's petition for approval to participate in a DER program and to recover DER program costs as a separate component of SCE&G's overall fuel factor. Under this order, SCE&G will, among other things, implement programs to encourage the development of renewable energy facilities with a total nameplate capacity of at least approximately 84.5 MW by the end of 2020, of which half is to be customer-scale solar capacity and half is to be utility-scale solar capacity. SCE&G is to make a good faith effort to have at least 30 MW of utility-scale solar capacity in service by the end of 2016.

By order dated September 16, 2015, the SCPSC approved SCE&G's request to adopt lower depreciation rates for electric and common plant effective January 1, 2015. These rates were based on the results of a depreciation study conducted by SCE&G using utility plant balances as of December 31, 2014. In connection with the adoption of the revised depreciation rates, SCE&G recorded lower depreciation expense of approximately $29 million ($.12 per share) in 2015, and pursuant to the SCPSC order, SCE&G reduced its electric operating revenues by approximately $14.5 million ($.06 per share) with an offset to under-collected fuel included within Receivables in the balance sheet. Accordingly, the Company's net income for 2015 increased approximately $9.8 million as a result of this change in estimate.

In October 2015, the SCPSC initiated its 2016 annual review of base rates for fuel costs. A public hearing for this annual review is scheduled for April 7, 2016.

Electric - Base Rates

Prior to 2014, certain of SCE&G's electric rates included an adjustment for eWNA. The eWNA was designed to mitigate the effects of abnormal weather on residential and commercial customers' bills. On November 26, 2013, SCE&G, ORS and certain other parties filed a joint petition with the SCPSC requesting, among other things, that the SCPSC discontinue the eWNA effective with bills rendered on or after the first billing cycle of January 2014. On December 20, 2013, the SCPSC granted the relief requested in the joint petition. In connection with the termination of the eWNA effective December 31, 2013, and pursuant to an SCPSC order, electric revenues were reduced to reverse the prior accrual of an under-collected balance of $8.5 million. This revenue reduction was fully offset by the recognition within other income of $8.5 million of gains realized upon the settlement of certain interest rate derivatives, which gains had been deferred as a regulatory liability.

Pursuant to an SCPSC order, SCE&G removes from rate base deferred income tax assets arising from capital expenditures related to the New Units and accrues carrying costs on those amounts during periods in which they are not included in rate base. Such carrying costs are determined at SCE&G's weighted average long-term debt borrowing rate and are recorded as a regulatory asset and other income. Carrying costs totaled $9.5 million and $5.8 million during 2015 and 2014, respectively. SCE&G anticipates that when the New Units are placed in service and accelerated tax depreciation is recognized on them, these deferred income tax assets will decline. When these assets are fully offset by related deferred income tax liabilities, the carrying cost accruals will cease, and the regulatory asset will begin to be amortized.

The SCPSC has approved a suite of DSM Programs for development and implementation. SCE&G offers to its retail electric customers several distinct programs designed to assist customers in reducing their demand for electricity and improving their energy efficiency. SCE&G submits annual filings to the SCPSC related to these programs which include actual program costs, net lost revenues (both forecasted and actual), customer incentives, and net program benefits, among other things. As actual DSM Program costs are incurred, they are deferred as regulatory assets and recovered through a rate rider approved by the SCPSC. The rate rider also provides for recovery of net lost revenues and for a shared savings incentive. The SCPSC approved the following rate riders pursuant to the annual DSM Programs filings, which went into effect as indicated below:

Year	Effective	Amount
2015	First billing cycle of May	$32.0 million
2014	First billing cycle of May	$15.4 million
2013	First billing cycle of May	$16.9 million

Year	Effective	Amount
2015	First billing cycle of May	$32.0 million
2014	First billing cycle of May	$15.4 million
2013	First billing cycle of May	$16.9 million

In April 2014, the SCPSC issued an order approving, among other things, SCE&G's request to utilize approximately $17.8 million of the gains from the late 2013 settlement of certain interest rate derivative instruments, previously deferred as regulatory liabilities, to offset a portion of SCE&G's DSM Programs rate rider. This order also allowed SCE&G to apply $5.0 million of its storm damage reserve and $5.0 million of the gains from the settlement of certain interest rate derivative instruments to offset previously deferred amounts.

In January 2016, SCE&G submitted its annual DSM Programs filing to the SCPSC. If approved, the filing would allow recovery of $37.6 million of costs and net lost revenues associated with the DSM Programs, along with an incentive to invest in such programs.

Electric - BLRA

Under the BLRA, SCE&G may file revised rates with the SCPSC each year to incorporate the financing cost of any incremental construction work in progress incurred for new nuclear generation. Through 2015, requested rate adjustments have been based on SCE&G's updated cost of debt and capital structure and on an allowed return on common equity of 11.0%. The SCPSC has approved recovery of the following amounts under the BLRA effective for bills rendered on and after October 30 in the following years:

Year	**Increase**	**Amount**
2015	2.6%	$64.5 million
2014	2.8%	$66.2 million
2013	2.9%	$67.2 million

In September 2015, the SCPSC approved a revision to the allowed return on equity for new nuclear construction from 11.0% to 10.5%. This revised return on equity will be applied prospectively for the purpose of calculating revised rates sought by SCE&G under the BLRA on and after January 1, 2016, until such time as the New Units are completed. See Note 10.

Gas - SCE&G

The RSA is designed to reduce the volatility of costs charged to customers by allowing for more timely recovery of the costs that regulated utilities incur related to natural gas infrastructure. The SCPSC has approved the following rate changes pursuant to annual RSA filings effective with the first billing cycle of November in the following years:

Year	**Action**	**Amount**
2015	No change	—
2014	0.6% Decrease	$2.6 million
2013	No change	—

SCE&G's natural gas tariffs include a PGA that provides for the recovery of actual gas costs incurred, including transportation costs. SCE&G's gas rates are calculated using a methodology which may adjust the cost of gas monthly based on a 12-month rolling average, and its gas purchasing policies and practices are reviewed annually by the SCPSC. The annual reviews conducted for each of the 12-month periods ended July 31, 2015 and 2014 resulted in the SCPSC issuing an order finding that SCE&G's gas purchasing policies and practices during each of the review periods were reasonable and prudent.

Gas - PSNC Energy

PSNC Energy's Rider D rate mechanism allows it to recover from customers all prudently incurred gas costs and certain related uncollectible expenses as well as losses on negotiated gas and transportation sales.

PSNC Energy establishes rates using a benchmark cost of gas approved by the NCUC, which may be periodically adjusted to reflect changes in the market price of natural gas. PSNC Energy revises its tariffs as necessary to track these changes and accounts for any over- or under-collection of the delivered cost of gas in its deferred accounts for subsequent rate

consideration. The NCUC reviews PSNC Energy's gas purchasing practices annually. In addition, PSNC Energy utilizes a CUT which allows it to consideration. The NCUC reviews PSNC Energy's gas purchasing practices annually. In addition, PSNC Energy utilizes a CUT which allows it to adjust its base rates semi-annually for residential and commercial customers based on average per customer consumption.

In October 2015, in connection with PSNC Energy's 2015 Annual Prudence Review, the NCUC determined that PSNC Energy's gas costs, including all hedging transactions, were reasonable and prudently incurred during the 12 months ended March 31, 2015.

In May 2014, the NCUC issued an order requiring utilities to adjust rates to reflect changes in the state corporate income tax rate that had been enacted by the North Carolina legislature and to file a proposal to refund amounts previously collected on a provisional basis. Pursuant to the order, PSNC Energy lowered its rates effective July 1, 2014, and refunded the amounts previously collected through the normal operation of its Rider D rate mechanism. These amounts were not significant for any period presented.

Regulatory Assets and Regulatory Liabilities

The Company's cost-based, rate-regulated utilities recognize in their financial statements certain revenues and expenses in different time periods than do enterprises that are not rate-regulated. As a result, the Company has recorded regulatory assets and regulatory liabilities which are summarized in the following tables. Other than unrecovered plant, substantially all regulatory assets are either explicitly excluded from rate base or are effectively excluded from rate base due to their being offset by related liabilities.

	December 31,	
Millions of dollars	**2015**	**2014**
Regulatory Assets:		
Accumulated deferred income taxes	$ 298	$ 284
AROs and related funding	405	366
Deferred employee benefit plan costs	325	350
Deferred losses on interest rate derivatives	535	453
Unrecovered plant	127	137
Environmental remediation costs	42	40
DSM Programs	61	56
Other	144	137
Total Regulatory Assets	$ 1,937	$ 1,823
Regulatory Liabilities:		
Asset removal costs	$ 732	$ 703
Deferred gains on interest rate derivatives	96	82
Other	27	29
Total Regulatory Liabilities	$ 855	$ 814

Accumulated deferred income tax liabilities that arose from utility operations that have not been included in customer rates are recorded as a regulatory asset. Substantially all of these regulatory assets relate to AFC and are expected to be recovered over the remaining lives of the related property which may range up to approximately 85 years.

ARO and related funding represents the regulatory asset associated with the legal obligation to decommission and dismantle Summer Station and conditional AROs related to generation, transmission and distribution properties, including gas pipelines. These regulatory assets are expected to be recovered over the related property lives and periods of decommissioning which may range up to approximately 110 years.

Employee benefit plan costs of the regulated utilities have historically been recovered as they have been recorded under GAAP. Deferred employee benefit plan costs represent amounts of pension and other postretirement benefit costs which were accrued as liabilities and treated as regulatory assets pursuant to FERC guidance, and costs deferred pursuant to specific SCPSC regulatory orders. Accordingly, in 2013 SCE&G began recovering through utility rates approximately $63 million of deferred pension costs for electric operations over approximately 30 years and approximately $14 million of deferred pension costs for gas operations over approximately 14 years. The remainder of the deferred benefit costs are expected to be recovered through utility rates, primarily over average service periods of participating employees, or up to approximately 12 years.

Deferred losses or gains on interest rate derivatives represent (i) the effective portions of changes in fair value and payments made or received upon settlement of certain interest rate derivatives designated as cash flow hedges and (ii) the changes in fair value and payments made or received upon settlement of certain other interest rate derivatives not so designated. The amounts recorded with respect to (i) are expected to be amortized to interest expense over the lives of the underlying debt through 2043. The amounts recorded with respect to (ii) are expected to be similarly amortized to interest expense through 2065 except when, in the case of deferred gains, such amounts are applied otherwise at the direction of the SCPSC.

Unrecovered plant represents the carrying value of coal-fired generating units, including related materials and supplies inventory, retired from service prior to being fully depreciated. Pursuant to SCPSC approval, SCE&G will amortize these amounts through cost of service rates over the units' previous estimated remaining useful lives through approximately 2025. Unamortized amounts are included in rate base and are earning a current return.

Environmental remediation costs represent costs associated with the assessment and clean-up of sites currently or formerly owned by the Company, and are expected to be recovered over periods of up to approximately 24 years.

DSM Programs represent deferred costs associated with such programs. As a result of the April 2015 SCPSC order, deferred costs are currently being recovered over approximately five years through an approved rate rider.

Various other regulatory assets are expected to be recovered in rates over periods of up to approximately 30 years.

Asset removal costs represent estimated net collections through depreciation rates of amounts to be incurred for the removal of assets in the future.

The SCPSC, the NCUC or the FERC has reviewed and approved through specific orders most of the items shown as regulatory assets. Other regulatory assets include, but are not limited to, certain costs which have not been specifically approved for recovery by the SCPSC, the NCUC or by the FERC. In recording such costs as regulatory assets, management believes the costs will be allowable under existing rate-making concepts that are embodied in rate orders received by the Company. The costs are currently not being recovered, but are expected to be recovered through rates in future periods. In the future, as a result of deregulation or other changes in the regulatory environment or changes in accounting requirements, the Company could be required to write off its regulatory assets and liabilities. Such an event could have a material effect on the Company's results of operations, liquidity or financial position in the period the write-off would be recorded.

3. COMMON EQUITY

The Company’s articles of incorporation do not limit the dividends that may be paid on its common stock. However, SCE&G’s bond indenture and PSNC Energy’s note purchase and debenture purchase agreements each contain provisions that, under certain circumstances, which the Company considers to be remote, could limit the payment of cash dividends on their respective common stock.

The Federal Power Act requires the appropriation of a portion of certain earnings from hydroelectric projects. At December 31, 2015 and 2014, retained earnings of approximately $72.4 million and $67.7 million, respectively, were restricted by this requirement as to payment of cash dividends on SCE&G’s common stock.

Authorized shares of common stock were 200 million as of December 31, 2015 and 2014.

SCANA issued common stock valued at $14.3 million, $99.3 million and $100.9 million (when issued) during the years ended December 31, 2015, 2014 and 2013, respectively, to satisfy the requirements of various compensation and dividend reinvestment plans. In addition, in March 2013, SCANA settled all forward sales contracts related to its common stock through the issuance of approximately 6.6 million common shares, resulting in net proceeds of approximately $196.2 million.

4. LONG-TERM AND SHORT-TERM DEBT

Total long-term debt, net reflects the retrospective adoption of accounting guidance for unamortized debt issuance costs in the fourth quarter of 2015 (see Note 1). Long-term debt by type with related weighted average effective interest rates and maturities at December 31 is as follows:

		2015		2014	
Dollars in millions	**Maturity**	**Balance**	**Rate**	**Balance**	**Rate**
SCANA Medium Term Notes (unsecured)	2020 - 2022	$ 800	5.42%	$ 800	5.42%

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Total long-term debt, net reflects the retrospective adoption of accounting guidance for unamortized debt issuance costs in the fourth quarter of 2015 (see Note 1). Long-term debt by type with related weighted average effective interest rates and maturities at December 31 is as follows:

		2015		2014	
Dollars in millions	**Maturity**	**Balance**	**Rate**	**Balance**	**Rate**
SCANA Medium Term Notes (unsecured)	2020 - 2022	$ 800	5.42%	$ 800	5.42%
SCANA Senior Notes (unsecured) (a)	2016 - 2034	84	1.11%	88	0.93%
SCE&G First Mortgage Bonds (secured)	2018 - 2065	4,340	5.78%	3,840	5.56%
GENCO Notes (secured)	2016 - 2024	220	5.92%	227	5.90%
Industrial and Pollution Control Bonds (b)	2028 - 2038	122	3.51%	122	3.51%
PSNC Senior Debentures	2020 - 2026	350	5.93%	350	5.93%
Nuclear Fuel Financing	2016	100	0.78%	100	0.78%
Other (c)	2016 - 2027	18	2.72%	167	7.39%
Total debt		6,034		5,694	
Current maturities of long-term debt		(116)		(166)	
Unamortized premium, net		—		3	
Unamortized debt issuance costs		(36)		(34)	
Total long-term debt, net		$ 5,882		$ 5,497	

(a) Variable rate notes hedged by a fixed interest rate swap (fixed rate of 6.17%).
(b) Includes variable rate debt of $67.8 million at December 31, 2015 (rate of 0.03%) and 2014 (rate of 0.04%) which are hedged by fixed swaps.
(c) Includes Junior Subordinated Notes redeemed at par prior to maturity on February 2, 2015, and included in the current portion of long-term debt on the balance sheet at December 31, 2014.

In May 2015, SCE&G issued $500 million of 5.1% first mortgage bonds due June 1, 2065. Proceeds from this sale were used to repay short-term debt primarily incurred as a result of SCE&G's construction program, to finance capital expenditures, and for general corporate purposes.

In May 2014, SCE&G issued $300 million of 4.5% first mortgage bonds due June 1, 2064. Proceeds from this sale were used to repay short-term debt primarily incurred as a result of SCE&G's construction program, to finance capital expenditures, and for general corporate purposes.

Long-term debt maturities will be $116 million in 2016, $15 million in 2017, $724 million in 2018, $13 million in 2019 and $363 million in 2020.

Substantially all electric utility plant is pledged as collateral in connection with long-term debt.

SCE&G is subject to a bond indenture dated April 1, 1993 (Mortgage) covering substantially all of its electric properties under which all of its first mortgage bonds (Bonds) have been issued. Bonds may be issued under the Mortgage in an aggregate principal amount not exceeding the sum of (1) 70% of Unfunded Net Property Additions (as therein defined), (2) the aggregate principal amount of retired Bonds and (3) cash deposited with the trustee. Bonds, other than certain Bonds issued on the basis of retired Bonds, may be issued under the Mortgage only if Adjusted Net Earnings (as therein defined) for 12 consecutive months out of the 18 months immediately preceding the month of issuance are at least twice (2.0) the annual interest requirements on all outstanding Bonds and Bonds to be outstanding (Bond Ratio). For the year ended December 31, 2015, the Bond Ratio was 5.17.

Lines of Credit and Short-Term Borrowings

At December 31, 2015 and 2014, SCANA, SCE&G (including Fuel Company) and PSNC Energy had available the following committed LOC and had outstanding the following LOC-related obligations and commercial paper borrowings:

Lines of Credit and Short-Term Borrowings

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	SCANA		SCE&G		PSNC Energy	
Millions of dollars	**2015**	**2014**	**2015**	**2014**	**2015**	**2014**
Lines of Credit:						
Total committed long-term	$ 400	$ 300	$ 1,400	$ 1,400	$ 200	$ 100
Outstanding commercial paper (270 or fewer days)	$ 37	$ 179	$ 420	$ 709	$ 74	$ 30
Weighted average interest rate	1.19%	0.54%	0.74%	0.52%	0.77%	0.65%
Letters of credit supported by LOC	$ 3	$ 3	$ 0.3	$ 0.3	—	—
Available	$ 360	$ 118	$ 980	$ 691	$ 126	$ 70

SCANA, SCE&G (including Fuel Company) and PSNC Energy are parties to five-year credit agreements in the amounts of $400 million, $1.2 billion (of which $500 million relates to Fuel Company) and $200 million, respectively. In addition, SCE&G is party to a three-year credit agreement in the amount of $200 million. In December 2015, the term of the five-year agreements was amended and extended by one year, such that they expire in December 2020. The three-year agreement expires in December 2018. These credit agreements are used for general corporate purposes, including liquidity support for each company's commercial paper program and working capital needs and, in the case of Fuel Company, to finance or refinance the purchase of nuclear fuel, certain fossil fuels, and emission and other environmental allowances. These committed long-term facilities are revolving lines of credit under credit agreements with a syndicate of banks. Wells Fargo Bank, National Association, Bank of America, N.A. and Morgan Stanley Bank, N.A. each provide 9.5% of the aggregate credit facilities, JPMorgan Chase Bank, N.A., Mizuho Corporate Bank, Ltd., TD Bank N.A., Credit Suisse AG, Cayman Islands Branch, UBS Loan Finance LLC, MUFG Union Bank, N.A., and Branch Banking and Trust Company each provide 7.9%, and Royal Bank of Canada and U.S. Bank National Association each provide 5.5%. Two other banks provide the remaining support. The Company pays fees to the banks as compensation for maintaining the committed lines of credit. Such fees were not material in any period presented.

On January 29, 2015, SCANA entered into an unsecured, three-month credit agreement in the amount of $150 million. SCANA entered this agreement to ensure sufficient liquidity was available to redeem its junior subordinated notes on February 2, 2015. No borrowings were made under this agreement, and it expired according to its terms on February 6, 2015.

The Company is obligated with respect to an aggregate of $67.8 million of industrial revenue bonds which are secured by letters of credit issued by TD Bank N.A. The letters of credit expire, subject to renewal, in the fourth quarter of 2019.

5. INCOME TAXES

Components of income tax expense are as follows:

Millions of dollars	**2015**	**2014**	**2013**
Current taxes:			
Federal	$ 382	$ 38	$ 161
State	57	(4)	17
Total current taxes	439	34	178
Deferred tax (benefit) expense, net:			
Federal	(36)	184	39
State	(7)	34	10
Total deferred taxes	(43)	218	49
Investment tax credits:			
Amortization of amounts deferred-state	(1)	(1)	(1)
Amortization of amounts deferred-federal	(2)	(3)	(3)
Total investment tax credits	(3)	(4)	(4)
Total income tax expense	$ 393	$ 248	$ 223

The difference between actual income tax expense and the amount calculated from the application of the statutory 35% federal income tax rate to pre-tax income is reconciled as follows:

Millions of dollars	2015	2014	2013
Net income	$ 746	$ 538	$ 471
Income tax expense	393	248	223
Total pre-tax income	$ 1,139	$ 786	$ 694
Income taxes on above at statutory federal income tax rate	$ 399	$ 275	$ 243
Increases (decreases) attributed to:			
State income taxes (less federal income tax effect)	38	24	22
State investment tax credits (less federal income tax effect)	(6)	(5)	(5)
Allowance for equity funds used during construction	(9)	(11)	(9)
Deductible dividends—401(k) Retirement Savings Plan	(10)	(10)	(10)
Amortization of federal investment tax credits	(2)	(3)	(3)
Section 41 tax credits	1	(3)	—
Section 45 tax credits	(9)	(9)	(5)
Domestic production activities deduction	(18)	(7)	(11)
Realization of basis differences upon sale of subsidiaries	7	—	—
Other differences, net	2	(3)	1
Total income tax expense	$ 393	$ 248	$ 223

The tax effects of significant temporary differences comprising the Company’s net deferred tax liability are as follows:

Millions of dollars	2015	2014
Deferred tax assets:		
Nondeductible accruals	$ 135	$ 127
Asset retirement obligation, including nuclear decommissioning	199	216
Financial instruments	35	40
Unamortized investment tax credits	16	17
Deferred fuel costs	8	—
Monetization of bankruptcy claim	—	10
Other	5	10
Total deferred tax assets	398	420
Deferred tax liabilities:		
Property, plant and equipment	$ 1,906	$ 1,928
Deferred employee benefit plan costs	96	107
Regulatory asset, asset retirement obligation	135	122
Deferred fuel costs	—	27
Regulatory asset, unrecovered plant	49	53
Regulatory asset, net loss on interest rate derivative contracts settlement	—	21
Demand side management costs	23	21
Prepayments	31	27
Other	65	45
Total deferred tax liabilities	2,305	2,351
Net deferred tax liability	$ 1,907	$ 1,931

During the third quarter of 2013, the State of North Carolina passed legislation that lowered the state corporate income tax rate from 6.9% to 6.0% in 2014, 5.0% in 2015 and 4.0% in 2016. In connection with this change in tax rates, related state deferred tax amounts were remeasured, with the change in their balances being credited to a regulatory liability. The change in income tax rates did not and is not expected to have a material impact on the Company’s financial position, results of operations or cash flows.

The Company files consolidated federal income tax returns, and the Company and its subsidiaries file various applicable state and local income tax returns. The IRS has completed examinations of the Company’s federal returns through 2004, and the Company’s federal returns through 2007 are closed for additional assessment. The IRS is currently examining

SCANA's open federal returns through 2014 as a result of claims discussed below in Changes to Unrecognized Tax Benefits. With few exceptions, the Company is no longer subject to state and local income tax examinations by tax authorities for years before 2010.

Changes to Unrecognized Tax Benefits

Millions of dollars	**2015**	**2014**	**2013**
Unrecognized tax benefits, January 1	$ 16	$ 3	—
Gross increases—uncertain tax positions in prior period	33	—	—
Gross decreases—uncertain tax positions in prior period	(2)	—	—
Gross increases—current period uncertain tax positions	2	13	$ 3
Unrecognized tax benefits, December 31	$ 49	$ 16	$ 3

During 2013 and 2014, the Company amended certain of its tax returns to claim certain tax-defined research and development deductions and credits and its related impact on domestic production activities. The Company also made similar claims in filing its 2013 and 2014 returns in 2014 and 2015, respectively. In connection with these federal and state filings, the Company recorded an unrecognized tax benefit of $49 million. During 2015, as the IRS' examination of these claims progressed, without resolution, the Company evaluated and recorded adjustments to its unrecognized tax benefits; however, none of these changes materially affected the Company's effective tax rate. If recognized, $17 million of the tax benefits would affect the Company's effective tax rate. It is reasonably possible that these tax benefits will increase by an additional $7 million within the next 12 months. It is also reasonably possible that these tax benefits may decrease by $8 million within the next 12 months. No other material changes in the status of the Company’s tax positions have occurred through December 31, 2015.

The Company recognizes interest accrued related to unrecognized tax benefits within interest expense or interest income and recognizes tax penalties within other expenses. In connection with the resolution of the uncertainty and recognition of the tax benefit, the Company has not recorded a material amount of interest income, interest expense, or penalties associated with any uncertain tax position.

6. DERIVATIVE FINANCIAL INSTRUMENTS

The Company recognizes all derivative instruments as either assets or liabilities in its statements of financial position and measures those instruments at fair value. The Company recognizes changes in the fair value of derivative instruments either in earnings, as a component of other comprehensive income (loss) or, for regulated subsidiaries, within regulatory assets or regulatory liabilities, depending upon the intended use of the derivative and the resulting designation.

Policies and procedures and risk limits are established to control the level of market, credit, liquidity and operational and administrative risks assumed by the Company. SCANA’s Board of Directors has delegated to a Risk Management Committee the authority to set risk limits, establish policies and procedures for risk management and measurement, and oversee and review the risk management process and infrastructure for SCANA and each of its subsidiaries. The Risk Management Committee, which is comprised of certain officers, including the Company’s Risk Management Officer and senior officers, apprises the Audit Committee of the Board of Directors with regard to the management of risk and brings to their attention significant areas of concern. Written policies define the physical and financial transactions that are approved, as well as the authorization requirements and limits for transactions.

Commodity Derivatives

The Company uses derivative instruments to hedge forward purchases and sales of natural gas, which create market risks of different types. Instruments designated as cash flow hedges are used to hedge risks associated with fixed price obligations in a volatile market and risks associated with price differentials at different delivery locations. Instruments designated as fair value hedges are used to mitigate exposure to fluctuating market prices created by fixed prices of stored natural gas. The basic types of financial instruments utilized are exchange-traded instruments, such as NYMEX futures contracts or options, and over-the-counter instruments such as options and swaps, which are typically offered by energy companies and financial institutions. Cash settlements of commodity derivatives are classified as operating activities in the consolidated statement of cash flows.

PSNC Energy hedges natural gas purchasing activities using over-the-counter options and swaps and NYMEX futures and options. PSNC Energy’s tariffs also include a provision for the recovery of actual gas costs incurred, including any costs of hedging. PSNC Energy records

SCANA's open federal returns through 2014 as a result of claims discussed below in Changes to Unrecognized Tax Benefits. With few exceptions, the Company is no longer subject to state and local income tax examinations by tax authorities for years before 2010.

Changes to Unrecognized Tax Benefits

Millions of dollars	**2015**	**2014**	**2013**
Unrecognized tax benefits, January 1	$ 16	$ 3	—
Gross increases—uncertain tax positions in prior period	33	—	—
Gross decreases—uncertain tax positions in prior period	(2)	—	—
Gross increases—current period uncertain tax positions	2	13	$ 3
Unrecognized tax benefits, December 31	$ 49	$ 16	$ 3

During 2013 and 2014, the Company amended certain of its tax returns to claim certain tax-defined research and development deductions and credits and its related impact on domestic production activities. The Company also made similar claims in filing its 2013 and 2014 returns in 2014 and 2015, respectively. In connection with these federal and state filings, the Company recorded an unrecognized tax benefit of $49 million. During 2015, as the IRS' examination of these claims progressed, without resolution, the Company evaluated and recorded adjustments to its unrecognized tax benefits; however, none of these changes materially affected the Company's effective tax rate. If recognized, $17 million of the tax benefits would affect the Company's effective tax rate. It is reasonably possible that these tax benefits will increase by an additional $7 million within the next 12 months. It is also reasonably possible that these tax benefits may decrease by $8 million within the next 12 months. No other material changes in the status of the Company's tax positions have occurred through December 31, 2015.

The Company recognizes interest accrued related to unrecognized tax benefits within interest expense or interest income and recognizes tax penalties within other expenses. In connection with the resolution of the uncertainty and recognition of the tax benefit, the Company has not recorded a material amount of interest income, interest expense, or penalties associated with any uncertain tax position.

6. DERIVATIVE FINANCIAL INSTRUMENTS

The Company recognizes all derivative instruments as either assets or liabilities in its statements of financial position and measures those instruments at fair value. The Company recognizes changes in the fair value of derivative instruments either in earnings, as a component of other comprehensive income (loss) or, for regulated subsidiaries, within regulatory assets or regulatory liabilities, depending upon the intended use of the derivative and the resulting designation.

Policies and procedures and risk limits are established to control the level of market, credit, liquidity and operational and administrative risks assumed by the Company. SCANA's Board of Directors has delegated to a Risk Management Committee the authority to set risk limits, establish policies and procedures for risk management and measurement, and oversee and review the risk management process and infrastructure for SCANA and each of its subsidiaries. The Risk Management Committee, which is comprised of certain officers, including the Company's Risk Management Officer and senior officers, apprises the Audit Committee of the Board of Directors with regard to the management of risk and brings to their attention significant areas of concern. Written policies define the physical and financial transactions that are approved, as well as the authorization requirements and limits for transactions.

Commodity Derivatives

The Company uses derivative instruments to hedge forward purchases and sales of natural gas, which create market risks of different types. Instruments designated as cash flow hedges are used to hedge risks associated with fixed price obligations in a volatile market and risks associated with price differentials at different delivery locations. Instruments designated as fair value hedges are used to mitigate exposure to fluctuating market prices created by fixed prices of stored natural gas. The basic types of financial instruments utilized are exchange-traded instruments, such as NYMEX futures contracts or options, and over-the-counter instruments such as options and swaps, which are typically offered by energy companies and financial institutions. Cash settlements of commodity derivatives are classified as operating activities in the consolidated statement of cash flows.

PSNC Energy hedges natural gas purchasing activities using over-the-counter options and swaps and NYMEX futures and options. PSNC Energy's tariffs also include a provision for the recovery of actual gas costs incurred, including any costs of hedging. PSNC Energy records premiums, transaction fees, margin requirements and any realized gains or losses from its

hedging program in deferred accounts as a regulatory asset or liability for the over- or under-recovery of gas costs. These derivative financial instruments are not designated as hedges for accounting purposes.

Unrealized gains and losses on qualifying cash flow hedges of nonregulated operations are deferred in AOCI. When the hedged hedging program in deferred accounts as a regulatory asset or liability for the over- or under-recovery of gas costs. These derivative financial instruments are not designated as hedges for accounting purposes.

Unrealized gains and losses on qualifying cash flow hedges of nonregulated operations are deferred in AOCI. When the hedged transactions affect earnings, previously recorded gains and losses are reclassified from AOCI to cost of gas. The effects of gains or losses resulting from these hedging activities are either offset by the recording of the related hedged transactions or are included in gas sales pricing decisions made by the business unit.

As an accommodation to certain customers, SEMI, as part of its energy management services, offers fixed price supply contracts which are accounted for as derivatives. These sales contracts are offset by the purchase of supply futures and swaps which are also accounted for as derivatives. Neither the sales contracts nor the related supply futures and swaps are designated as hedges for accounting purposes.

Interest Rate Swaps

The Company may use interest rate swaps to manage interest rate risk and exposure to changes in fair value attributable to changes in interest rates on certain debt issuances. In cases in which the Company synthetically converts variable rate debt to fixed rate debt using swaps that are designated as cash flow hedges, periodic payments to or receipts from swap counterparties related to these derivatives are recorded within interest expense.

In anticipation of the issuance of debt, the Company may use treasury rate lock or forward starting swap agreements that are designated as cash flow hedges. Except as described in the following paragraph, the effective portions of changes in fair value and payments made or received upon termination of such agreements for regulated subsidiaries are recorded in regulatory assets or regulatory liabilities. For the holding company or nonregulated subsidiaries, such amounts are recorded in AOCI. Such amounts are amortized to interest expense over the term of the underlying debt. Ineffective portions of fair value changes are recognized in income.

Pursuant to regulatory orders, interest derivatives entered into by SCE&G after October 2013 are not designated as cash flow hedges and fair value changes and settlement amounts are recorded as regulatory assets and liabilities. Settlement losses on swaps will be amortized over the lives of subsequent debt issuances and gains may be applied to under-collected fuel, may be amortized to interest expense or may be applied as otherwise directed by the SCPSC. As discussed in Note 2, in 2013 the SCPSC directed SCE&G to recognize $41.6 million and $8.5 million of realized gains (which had been deferred in regulatory liabilities) within other income in 2013, fully offsetting revenue reductions related to under-collected fuel balances and under-collected amounts arising under the eWNA program which was terminated at the end of 2013. As also discussed in Note 2, pursuant to regulatory orders in 2014, the SCPSC directed SCE&G to apply $46 million of these deferred gains to reduce under-collected fuel to utilize approximately $17.8 million of these gains to offset a portion of the net lost revenues component of SCE&G's DSM Program rider, and to apply $5.0 million of the gains to the remaining balance of deferred net lost revenues as of April 30, 2014, which had been deferred within regulatory assets.

Cash payments made or received upon settlement of these financial instruments are classified as investing activities for cash flow statement purposes.

Quantitative Disclosures Related to Derivatives

The Company was party to natural gas derivative contracts outstanding in the following quantities:

	Commodity and Other Energy Management Contracts (in MMBTU)			
Hedge designation	**Gas Distribution**	**Retail Gas Marketing**	**Energy Marketing**	**Total**
As of December 31, 2015				
Commodity	7,530,000	7,869,000	3,973,500	19,372,500
Energy Management (a)	—	—	38,857,480	38,857,480
Total (a)	7,530,000	7,869,000	42,830,980	58,229,980
As of December 31, 2014				
Commodity	6,840,000	7,951,000	3,446,720	18,237,720
Energy Management (b)	—	—	37,495,339	37,495,339
Total (b)	6,840,000	7,951,000	40,942,059	55,733,059

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Hedge designation	**Gas Distribution**	**Retail Gas Marketing**	**Energy Marketing**	**Total**
As of December 31, 2015				
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Energy Management (a)	—	—	38,857,480	38,857,480
Total (a)	7,530,000	7,869,000	42,830,980	58,229,980
As of December 31, 2014				
Commodity	6,840,000	7,951,000	3,446,720	18,237,720
Energy Management (b)	—	—	37,495,339	37,495,339
Total (b)	6,840,000	7,951,000	40,942,059	55,733,059

(a) Includes an aggregate 1,842,048 MMBTU related to basis swap contracts in Energy Marketing.
(b) Includes an aggregate 933,893 MMBTU related to basis swap contracts in Energy Marketing.

The Company was party to interest rate swaps designated as cash flow hedges with aggregate notional amounts of $120.0 million at December 31, 2015 and $124.4 million at December 31, 2014. The Company was party to interest rate swaps not designated as cash flow hedges with an aggregate notional amount of $1.235 billion and $1.085 billion at December 31, 2015 and 2014, respectively.

The fair value of derivatives in the consolidated balance sheets is as follows:

Fair Values of Derivative Instruments

Millions of dollars	**Balance Sheet Location**	**Asset**	**Liability**
As of December 31, 2015			
Designated as hedging instruments			
Interest rate contracts	Derivative financial instruments		$ 4
	Other deferred credits and other liabilities		28
Commodity contracts	Other current assets		1
	Derivative financial instruments		4
Total			$ 37
Not designated as hedging instruments			
Interest rate contracts	Other current assets	$ 10	
	Other deferred debits and other assets	5	
	Derivative financial instruments		$ 33
	Other deferred credits and other liabilities		22
Commodity contracts	Other current assets	1	
Energy management contracts	Other current assets	11	2
	Other deferred debits and other assets	3	
	Derivative financial instruments		9
	Other deferred credits and other liabilities		3
Total		$ 30	$ 69

The fair value of derivatives in the consolidated balance sheets is as follows:

Fair Values of Derivative Instruments

Millions of dollars	**Balance Sheet Location**	**Asset**	**Liability**
As of December 31, 2015			
Designated as hedging instruments			
Interest rate contracts	Derivative financial instruments		$ 4
	Other deferred credits and other liabilities		28
Commodity contracts	Other current assets		1
	Derivative financial instruments		4
Total			$ 37
Not designated as hedging instruments			
Interest rate contracts	Other current assets	$ 10	
	Other deferred debits and other assets	5	
	Derivative financial instruments		$ 33
	Other deferred credits and other liabilities		22
Commodity contracts	Other current assets	1	
Energy management contracts	Other current assets	11	2
	Other deferred debits and other assets	3	
	Derivative financial instruments		9
	Other deferred credits and other liabilities		3
Total		$ 30	$ 69
As of December 31, 2014			
Designated as hedging instruments			
Interest rate contracts	Derivative financial instruments		$ 5
	Other deferred credits and other liabilities		28
Commodity contracts	Other current assets		1
	Derivative financial instruments		11
Total			$ 45
Not designated as hedging instruments			
Interest rate contracts	Derivative financial instruments		$ 207
	Other deferred credits and other liabilities		17
Commodity contracts	Other current assets	$ 1	
Energy management contracts	Other current assets	15	5
	Other deferred debits and other assets	5	
	Derivative financial instruments		10
	Other deferred credits and other liabilities		5
Total		$ 21	$ 244

Derivatives Designated as Fair Value Hedges

The Company had no interest rate or commodity derivatives designated as fair value hedges for any period presented.

Derivatives in Cash Flow Hedging Relationships

The effect of derivative instruments on the consolidated statements of income is as follows:

Millions of dollars	Gain or (Loss) Deferred in Regulatory Accounts (Effective Portion)	Loss Reclassified from Deferred Accounts into Income (Effective Portion) Location	Amount
Year Ended December 31, 2015			
Interest rate contracts	$ (3)	Interest expense	$ (3)
Year Ended December 31, 2014			
Interest rate contracts	$ (9)	Interest expense	$ (3)
Year Ended December 31, 2013			
Interest rate contracts	$ 106	Interest expense	$ (3)

Millions of dollars	Gain or (Loss) Recognized in OCI, net of tax (Effective Portion)	Gain (Loss) Reclassified from AOCI into Income, net of tax (Effective Portion) Location	Amount
Year Ended December 31, 2015			
Interest rate contracts	$ (2)	Interest expense	$ (7)
Commodity contracts	(10)	Gas purchased for resale	(15)
Total	$ (12)		$ (22)
Year Ended December 31, 2014			
Interest rate contracts	$ (6)	Interest expense	$ (7)
Commodity contracts	(8)	Gas purchased for resale	4
Total	$ (14)		$ (3)
Year Ended December 31, 2013			
Interest rate contracts	$ 5	Interest expense	$ (8)
Commodity contracts	2	Gas purchased for resale	(3)
Total	$ 7		$ (11)

As of December 31, 2015, the Company expects that during the next 12 months reclassifications from accumulated other comprehensive loss to earnings arising from cash flow hedges will include approximately $3.3 million as an increase to gas cost and approximately $7.1 million as an increase to interest expense, assuming natural gas and financial markets remain at their current levels. As of December 31, 2015, all of the Company's commodity cash flow hedges settle by their terms before the end of the second quarter of 2018.

As of December 31, 2015, the Company expects that during the next twelve months reclassifications from regulatory accounts to earnings arising from cash flow hedges designated as hedging instruments will include approximately $2.2 million as an increase to interest expense assuming financial markets remain at their current levels.

Hedge Ineffectiveness

Other gain (losses) recognized in income representing ineffectiveness on interest rate hedges designated as cash flow hedges were insignificant for all periods presented.

Derivatives Not Designated as Hedging Instruments

Millions of dollars	Gain (Loss) Deferred in Regulatory Accounts	Gain Reclassified from Deferred Accounts into Income Location	Amount
Year Ended December 31, 2015			
Interest rate contracts	$ (69)	Other income	$ 5
Year Ended December 31, 2014			
Interest rate contracts	$ (352)	Other income	$ 64
Year Ended December 31, 2013			
Interest rate contracts	$ 39	Other income	$ 50

Gains reclassified to other income offset revenue reductions as previously described herein and in Note 2.

As of December 31, 2015, the Company expects that during the next twelve months reclassifications from regulatory accounts to earnings arising from interest rate swaps not designated as cash flow hedges will include approximately $0.6 million as an increase to interest expense.

Credit Risk Considerations

The Company limits credit risk in its commodity and interest rate derivatives activities by assessing the creditworthiness of potential counterparties before entering into transactions with them and continuing to evaluate their creditworthiness on an ongoing basis. In this regard, the Company uses credit ratings provided by credit rating agencies and current market-based qualitative and quantitative data, as well as financial statements, to assess the financial health of counterparties on an ongoing basis. The Company uses standardized master agreements which generally include collateral requirements. These master agreements permit the netting of cash flows associated with a single counterparty. Cash, letters of credit and parental/affiliate guarantees may be obtained as security from counterparties in order to mitigate credit risk. The collateral agreements require a counterparty to post cash or letters of credit in the event an exposure exceeds the established threshold. The threshold represents an unsecured credit limit which may be supported by a parental/affiliate guaranty, as determined in accordance with the Company's credit policies and due diligence. In addition, collateral agreements allow for the termination and liquidation of all positions in the event of a failure or inability to post collateral.

Certain of the Company’s derivative instruments contain contingent provisions that require the Company to provide collateral upon the occurrence of specific events, primarily credit rating downgrades. As of December 31, 2015 and 2014, the Company had posted $50.4 million and $152.4 million, respectively, of collateral related to derivatives with contingent provisions that were in a net liability position. Collateral related to the positions expected to close in the next 12 months is recorded in Other Current Assets on the consolidated balance sheets. Collateral related to the noncurrent positions is recorded in Other within Deferred Debits and Other Assets on the consolidated balance sheets. If all of the contingent features underlying these instruments had been fully triggered as of December 31, 2015 and 2014, the Company would have been required to post an additional $44.8 million and $129.8 million, respectively, of collateral to its counterparties. The aggregate fair value of all derivative instruments with contingent provisions that are in a net liability position as of December 31, 2015 and 2014, are $95.2 million and $282.2 million, respectively.

In addition, as of December 31, 2015 and December 31, 2014, the Company has collected no cash collateral related to interest rate derivatives with contingent provisions that are in a net asset position. If all the contingent features underlying these instruments had been fully triggered as of December 31, 2015 and December 31, 2014, the Company could request $7.3 million and $- million, respectively, of cash collateral from its counterparties. The aggregate fair value of all derivative instruments with contingent provisions that are in a net asset position as of December 31, 2015 and December 31, 2014 is $7.3 million and $- million, respectively. In addition, at December 31, 2015, the Company could have called on letters of credit in the amount of $3.0 million related to $14.0 million in commodity derivatives that are in a net asset position, compared to letters of credit of $9.2 million related to derivatives of $20 million at December 31, 2014, if all the contingent features underlying these instruments had been fully triggered.

Information related to the Company's offsetting derivative assets and liabilities follows:

Offsetting Derivative Assets

				Gross Amounts Not Offset in the Statement of Financial Position		
Millions of dollars	Gross Amounts of Recognized Assets	Gross Amounts Offset in the Statement of Financial Position	Net Amounts Presented in the Statement of Financial Position	Financial Instruments	Cash Collateral Received	Net Amount
As of December 31, 2015						
Interest rate	$ 15	—	$ 15	$ (8)	—	$ 7
Commodity	1	—	1	—	—	1
Energy Management	15	$ (1)	14	—	—	14
Total	$ 31	$ (1)	$ 30	$ (8)	—	$ 22
Balance sheet location	Other current assets		$ 22			
	Other deferred debits and other assets		8			

Information related to the Company's offsetting derivative assets and liabilities follows:

Offsetting Derivative Assets

Millions of dollars	Gross Amounts of Recognized Assets	Gross Amounts Offset in the Statement of Financial Position	Net Amounts Presented in the Statement of Financial Position	Gross Amounts Not Offset in the Statement of Financial Position: Financial Instruments	Gross Amounts Not Offset in the Statement of Financial Position: Cash Collateral Received	Net Amount
As of December 31, 2015						
Interest rate	$ 15	—	$ 15	$ (8)	—	$ 7
Commodity	1	—	1	—	—	1
Energy Management	15	$ (1)	14	—	—	14
Total	$ 31	$ (1)	$ 30	$ (8)	—	$ 22

Balance sheet location	Other current assets	$ 22
	Other deferred debits and other assets	8
	Total	$ 30

Millions of dollars	Gross Amounts of Recognized Assets	Gross Amounts Offset in the Statement of Financial Position	Net Amounts Presented in the Statement of Financial Position	Gross Amounts Not Offset in the Statement of Financial Position: Financial Instruments	Gross Amounts Not Offset in the Statement of Financial Position: Cash Collateral Received	Net Amount
As of December 31, 2014						
Commodity	$ 1	—	$ 1	—	—	$ 1
Energy Management	20	—	20	—	—	20
Total	$ 21	—	$ 21	—	—	$ 21

Balance sheet location	Other current assets	$ 16
	Other deferred debits and other assets	5
	Total	$ 21

Offsetting Derivative Liabilities

Millions of dollars	Gross Amounts of Recognized Liabilities	Gross Amounts Offset in the Statement of Financial Position	Net Amounts Presented in the Statement of Financial Position	Gross Amounts Not Offset in the Statement of Financial Position: Financial Instruments	Gross Amounts Not Offset in the Statement of Financial Position: Cash Collateral Posted	Net Amount
As of December 31, 2015						
Interest rate	$ 87	—	$ 87	$ (8)	$ (36)	$ 43
Commodity	5	—	5	—	(5)	—
Energy Management	15	$ (1)	14	—	(9)	5
Total	$ 107	$ (1)	$ 106	$ (8)	$ (50)	$ 48

Balance sheet location	Other current assets	$ 3
	Derivative financial instruments	50
	Other deferred credits and other liabilities	53
	Total	$ 106

Millions of dollars	Gross Amounts of Recognized Liabilities	Gross Amounts Offset in the Statement of Financial Position	Net Amounts Presented in the Statement of Financial Position	Gross Amounts Not Offset in the Statement of Financial Position: Financial Instruments	Gross Amounts Not Offset in the Statement of Financial Position: Cash Collateral Posted	Net Amount
As of December 31, 2014						
Interest rate	$ 257	—	$ 257	—	$ (131)	$ 126
Commodity	12	—	12	—	(10)	2
Energy Management	20	—	20	—	(11)	9

Total	$ 289	—	$ 289	—	$ (152)	$ 137

Balance sheet location	Other current assets	$ 6
	Derivative financial instruments	233
	Other deferred credits and other liabilities	50
	Total	$ 289

7. FAIR VALUE MEASUREMENTS, INCLUDING DERIVATIVES

The Company values available for sale securities using quoted prices from a national stock exchange, such as the NASDAQ, where the securities are actively traded. For commodity derivative and energy management assets and liabilities, the Company uses unadjusted NYMEX prices to determine fair value, and considers such measures of fair value to be Level 1 for exchange traded instruments and Level 2 for over-the-counter instruments. The Company's interest rate swap agreements are valued using discounted cash flow models with independently sourced data. Fair value measurements, and the level within the fair value hierarchy in which the measurements fall, were as follows:

	As of December 31, 2015		As of December 31, 2014	
Millions of dollars	**Level 1**	**Level 2**	**Level 1**	**Level 2**
Assets:				
Available for sale securities	$ 11	—	$ 13	—
Interest rate contracts	—	$ 15	—	—
Commodity contracts	1	—	1	—
Energy management contracts	—	14	—	$ 20
Liabilities:				
Interest rate contracts	—	87	—	257
Commodity contracts	1	4	1	11
Energy management contracts	4	12	5	18

There were no Level 3 fair value measurements for either period presented, and there were no transfers of fair value amounts into or out of Levels 1, 2 or 3 during the periods presented.

Financial instruments for which the carrying amount may not equal estimated fair value at December 31, 2015 and December 31, 2014 were as follows:

	As of December 31, 2015		As of December 31, 2014	
Millions of dollars	**Carrying Amount**	**Estimated Fair Value**	**Carrying Amount**	**Estimated Fair Value**
Long-term debt	$ 5,997.6	$ 6,445.7	$ 5,663.1	$ 6,558.0

Fair values of long-term debt instruments are based on net present value calculations using independently sourced market data that incorporate a developed discount rate using similarly rated long-term debt, along with benchmark interest rates. As such, the aggregate fair values presented above are considered to be Level 2. Early settlement of long-term debt may not be possible or may not be considered prudent.

Carrying values of short-term borrowings approximate their fair values, which are based on quoted prices from dealers in the commercial paper market. These fair values are considered to be Level 2.

8. EMPLOYEE BENEFIT PLANS AND EQUITY COMPENSATION PLAN

Pension and Other Postretirement Benefit Plans

The Company sponsors a noncontributory defined benefit pension plan covering regular, full-time employees hired before January 1, 2014. The Company's policy has been to fund the plan as permitted by applicable federal income tax regulations, as determined by an independent actuary.

7. FAIR VALUE MEASUREMENTS, INCLUDING DERIVATIVES

The Company values available for sale securities using quoted prices from a national stock exchange, such as the NASDAQ, where the securities are actively traded. For commodity derivative and energy management assets and liabilities, the Company uses unadjusted NYMEX prices to determine fair value, and considers such measures of fair value to be Level 1 for exchange traded instruments and Level 2 for over-the-counter instruments. The Company's interest rate swap agreements are valued using discounted cash flow models with independently sourced data. Fair value measurements, and the level within the fair value hierarchy in which the measurements fall, were as follows:

	As of December 31, 2015		As of December 31, 2014	
Millions of dollars	**Level 1**	**Level 2**	**Level 1**	**Level 2**
Assets:				
Available for sale securities	$ 11	—	$ 13	—
Interest rate contracts	—	$ 15	—	—
Commodity contracts	1	—	1	—
Energy management contracts	—	14	—	$ 20
Liabilities:				
Interest rate contracts	—	87	—	257
Commodity contracts	1	4	1	11
Energy management contracts	4	12	5	18

There were no Level 3 fair value measurements for either period presented, and there were no transfers of fair value amounts into or out of Levels 1, 2 or 3 during the periods presented.

Financial instruments for which the carrying amount may not equal estimated fair value at December 31, 2015 and December 31, 2014 were as follows:

	As of December 31, 2015		As of December 31, 2014	
Millions of dollars	**Carrying Amount**	**Estimated Fair Value**	**Carrying Amount**	**Estimated Fair Value**
Long-term debt	$ 5,997.6	$ 6,445.7	$ 5,663.1	$ 6,558.0

Fair values of long-term debt instruments are based on net present value calculations using independently sourced market data that incorporate a developed discount rate using similarly rated long-term debt, along with benchmark interest rates. As such, the aggregate fair values presented above are considered to be Level 2. Early settlement of long-term debt may not be possible or may not be considered prudent.

Carrying values of short-term borrowings approximate their fair values, which are based on quoted prices from dealers in the commercial paper market. These fair values are considered to be Level 2.

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Pension and Other Postretirement Benefit Plans

The Company sponsors a noncontributory defined benefit pension plan covering regular, full-time employees hired before January 1, 2014. The Company's policy has been to fund the plan as permitted by applicable federal income tax regulations, as determined by an independent actuary.

The Company's pension plan provides benefits under a cash balance formula for employees hired before January 1, 2000 who elected that option and for all eligible employees hired subsequently. Under the cash balance formula, benefits accumulate as a result of compensation credits and interest credits. Employees hired before January 1, 2000 who elected to remain under the final average pay formula earn benefits based on years of credited service and the employee's average annual base earnings received during the last three years of employment. Benefits under the cash balance formula and the final average pay formula will continue to accrue through December 31, 2023, after which date no benefits will be accrued except that participants under the cash balance formula will continue to earn interest credits.

In addition to pension benefits, the Company provides certain unfunded postretirement health care and life insurance benefits to certain active and retired employees. Retirees hired before January 1, 2011 share in a portion of their medical care cost, while employees hired subsequently are responsible for the full cost of retiree medical benefits elected by them. The costs of postretirement benefits other than pensions are accrued during the years the employees render the services necessary to be eligible for these benefits.

Changes in Benefit Obligations

The measurement date used to determine pension and other postretirement benefit obligations is December 31. Data related to the changes in the projected benefit obligation for pension benefits and the accumulated benefit obligation for other postretirement benefits are presented below.

	Pension Benefits		Other Postretirement Benefits	
Millions of dollars	**2015**	**2014**	**2015**	**2014**
Benefit obligation, January 1	$ 919.5	$ 823.0	$ 268.2	$ 238.0
Service cost	24.1	20.0	5.3	4.6
Interest cost	38.2	40.4	11.4	12.0
Plan participants’ contributions	—	—	2.4	2.2
Actuarial (gain) loss	(62.4)	100.1	(21.2)	23.5
Benefits paid	(64.0)	(64.0)	(12.5)	(12.1)
Benefit obligation, December 31	$ 855.4	$ 919.5	$ 253.6	$ 268.2

The Company adopted new mortality tables and an improvement scale published by the Society of Actuaries in 2014, resulting in an actuarial loss for pension and other post retirement benefit obligations of approximately $26.3 million and $2.7 million, respectively, in 2014. In 2015, based on an evaluation of the mortality experience of the pension plan, the Company adopted a custom mortality table for purposes of measuring pension and other postretirement benefit obligations at year-end. This change resulted in an actuarial gain for pension and other postretirement benefit obligations of approximately $21.5 million and $2.4 million, respectively, in 2015.

The accumulated benefit obligation for pension benefits was $829.3 million at the end of 2015 and $888.3 million at the end of 2014. The accumulated pension benefit obligation differs from the projected pension benefit obligation above in that it reflects no assumptions about future compensation levels.

Significant assumptions used to determine the above benefit obligations are as follows:

	Pension Benefits		Other Postretirement Benefits	
	2015	**2014**	**2015**	**2014**
Annual discount rate used to determine benefit obligation	4.68%	4.20%	4.78%	4.30%
Assumed annual rate of future salary increases for projected benefit obligation	3.00%	3.00%	3.00%	3.00%

A 7.0% annual rate of increase in the per capita cost of covered health care benefits was assumed for 2015. The rate was assumed to decrease gradually to 5.0% for 2021 and to remain at that level thereafter.

A one percent increase in the assumed health care cost trend rate would increase the postretirement benefit obligation by $0.8 million at December 31, 2015 and by $1.3 million at December 31, 2014. A one percent decrease in the assumed health care cost trend rate would decrease the postretirement benefit obligation by $0.7 million at December 31, 2015 and by $1.0 million at December 31, 2014.

Funded Status

Millions of Dollars	Pension Benefits		Other Postretirement Benefits	
December 31,	**2015**	**2014**	**2015**	**2014**
Fair value of plan assets	$ 781.7	$ 861.8	—	—
Benefit obligation	855.4	919.5	$ 253.6	$ 268.2
Funded status	$ (73.7)	$ (57.7)	$ (253.6)	$ (268.2)

Amounts recognized on the consolidated balance sheets were as follows:

Amounts recognized on the consolidated balance sheets were as follows:

Millions of Dollars	Pension Benefits		Other Postretirement Benefits	
December 31,	2015	2014	2015	2014
Current liability	—	—	$ (11.9)	$ (11.2)
Noncurrent liability	$ (73.7)	$ (57.7)	(241.7)	(257.0)

Amounts recognized in accumulated other comprehensive loss were as follows:

Millions of Dollars	Pension Benefits		Other Postretirement Benefits	
December 31,	2015	2014	2015	2014
Net actuarial loss	$ 10.4	$ 8.1	$ 1.7	$ 3.0
Prior service cost	0.2	0.3	—	0.1
Total	$ 10.6	$ 8.4	$ 1.7	$ 3.1

Amounts recognized in regulatory assets were as follows:

Millions of Dollars	Pension Benefits		Other Postretirement Benefits	
December 31,	2015	2014	2015	2014
Net actuarial loss	$ 219.4	$ 222.1	$ 24.0	$ 43.8
Prior service cost	5.9	9.6	0.3	0.6
Total	$ 225.3	$ 231.7	$ 24.3	$ 44.4

In connection with the joint ownership of Summer Station, as of December 31, 2015 and 2014, the Company recorded within deferred debits $20.3 million and $17.8 million, respectively, attributable to Santee Cooper's portion of shared pension costs. As of December 31, 2015 and 2014, the Company also recorded within deferred debits $13.8 million and $15.1 million, respectively, from Santee Cooper, representing its portion of the unfunded postretirement benefit obligation.

Changes in Fair Value of Plan Assets

	Pension Benefits	
Millions of dollars	2015	2014
Fair value of plan assets, January 1	$ 861.8	$ 870.0
Actual return (loss) on plan assets	(16.1)	55.8
Benefits paid	(64.0)	(64.0)
Fair value of plan assets, December 31	$ 781.7	$ 861.8

Investment Policies and Strategies

The assets of the pension plan are invested in accordance with the objectives of (1) fully funding the obligations of the pension plan, (2) overseeing the plan's investments in an asset-liability framework that considers the funding surplus (or deficit) between assets and liabilities, and overall risk associated with assets as compared to liabilities, and (3) maintaining sufficient liquidity to meet benefit payment obligations on a timely basis. During 2013, in connection with the amendments to the plan, the Company adopted a dynamic investment strategy for the management of the pension plan assets. The strategy will lead to a reduction in equities and an increase in long duration fixed income allocations over time with the intention of reducing volatility of funded status and pension costs.

The pension plan operates with several risk and control procedures, including ongoing reviews of liabilities, investment objectives, levels of diversification, investment managers and performance expectations. The total portfolio is constructed and maintained to provide prudent diversification with regard to the concentration of holdings in individual issues, corporations, or industries.

Transactions involving certain types of investments are prohibited. These include, except where utilized by a hedge fund manager, any form of private equity; commodities or commodity contracts (except for unleveraged stock or bond index futures and currency futures and options); ownership of real estate in any form other than publicly traded securities; short sales, warrants or margin transactions, or any leveraged investments; and natural resource properties. Investments made for the purpose of engaging in speculative trading are also prohibited.

The Company's pension plan asset allocation at December 31, 2015 and 2014 and the target allocation for 2016 are as follows:

	Percentage of Plan Assets		
	Target Allocation	December 31,	
Asset Category	**2016**	**2015**	**2014**
Equity Securities	58%	57%	57%
Fixed Income	33%	32%	34%
Hedge Funds	9%	11%	9%

For 2016, the expected long-term rate of return on assets will be 7.50%. In developing the expected long-term rate of return assumptions, management evaluates the pension plan's historical cumulative actual returns over several periods, considers the expected active returns across various asset classes and assumes the target allocation is achieved. Management regularly reviews such allocations and periodically rebalances the portfolio when considered appropriate. Additional rebalancing may occur subject to funded status improvements as part of the dynamic investment strategy described previously.

Fair Value Measurements

Assets held by the pension plan are measured at fair value as described below. Assets are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. At December 31, 2015 and 2014, fair value measurements, and the level within the fair value hierarchy in which the measurements fall, were as follows:

	Fair Value Measurements at Reporting Date Using					
Millions of dollars	**Total**	**Level 2**	**Level 3**	**Total**	**Level 2**	**Level 3**
	December 31, 2015			*December 31, 2014*		
Mutual funds	$ 538	$ 538	—	$ 622	$ 622	—
Short-term investment vehicles	14	14	—	20	20	—
US Treasury securities	22	22	—	6	6	—
Corporate debt securities	78	78	—	86	86	—
Municipals	14	14	—	15	15	—
Limited partnerships	33	33	—	32	32	—
Multi-strategy hedge funds	83	—	$ 83	81	—	$ 81
	$ 782	$ 699	$ 83	$ 862	$ 781	$ 81

At December 31, 2015, assets with fair value measurements classified as Level 1 were insignificant. There were no transfers of fair value amounts into or out of Levels 1, 2 or 3 during 2015 or 2014.

The pension plan values certain mutual funds, where applicable, using unadjusted quoted prices from a national stock exchange, such as NYSE and NASDAQ, where the securities are actively traded. Other mutual funds and limited partnerships are valued using the observable prices of the underlying fund assets based on trade data for identical or similar securities or from a national stock exchange for similar assets or broker quotes. Short-term investment vehicles are funds that invest in short-term fixed income instruments and are valued using observable prices of the underlying fund assets based on trade data for identical or similar securities. Government agency securities are valued using quoted market prices or based on models using observable inputs from market sources such as external prices or spreads or benchmarked thereto. Corporate debt securities and municipals are valued based on recently executed transactions, using quoted market prices, or based on models using observable inputs from market sources such as external prices or spreads or benchmarked thereto. Hedge funds represent investments in a hedge fund of funds partnership that invests directly in multiple hedge fund strategies that are not traded on exchanges and do not trade on a daily basis. The fair value of this multi-strategy hedge fund is estimated based on the net asset value of the underlying hedge fund strategies using consistent valuation guidelines that account for variations that may impact their fair value. The estimated fair value is the price at which redemptions and subscriptions occur.

	Fair Value Measurements Level 3	
Millions of dollars	**2015**	**2014**

Millions of dollars	Fair Value Measurements Level 3 2015	2014
Beginning Balance	$ 81	$ 76
Unrealized gains included in changes in net assets	2	5
Purchases, issuances, and settlements	—	—
Ending Balance	$ 83	$ 81

Expected Cash Flows

The total benefits expected to be paid from the pension plan or from the Company's assets for the other postretirement benefits plan (net of participant contributions), respectively, are as follows:

Expected Benefit Payments

Millions of dollars	Pension Benefits	Other Postretirement Benefits
2016	$ 65.1	$ 11.9
2017	63.2	12.7
2018	64.7	13.5
2019	65.3	14.2
2020	65.8	14.9
2021-2025	338.3	80.5

Pension Plan Contributions

The pension trust is adequately funded under current regulations. No contributions have been required since 1997, and as a result of closing the plan to new entrants and freezing benefit accruals in the future, the Company does not anticipate making significant contributions to the pension plan for the foreseeable future.

Net Periodic Benefit Cost

The Company records net periodic benefit cost utilizing beginning of the year assumptions. Disclosures required for these plans are set forth in the following tables.

Components of Net Periodic Benefit Cost

	Pension Benefits			Other Postretirement Benefits		
Millions of dollars	2015	2014	2013	2015	2014	2013
Service cost	$ 24.1	$ 20.0	$ 21.8	$ 5.3	$ 4.6	$ 5.9
Interest cost	38.2	40.4	38.5	11.4	12.0	11.1
Expected return on assets	(62.0)	(66.7)	(61.4)	n/a	n/a	n/a
Prior service cost amortization	4.1	4.1	6.0	0.4	0.3	0.7
Amortization of actuarial losses	13.6	4.8	16.9	2.1	—	3.3
Transition obligation amortization	—	—	—	—	—	0.3
Curtailment	—	—	9.9	—	—	—
Net periodic benefit cost	$ 18.0	$ 2.6	$ 31.7	$ 19.2	$ 16.9	$ 21.3

In connection with regulatory orders, SCE&G recovers current pension expense through a rate rider that may be adjusted annually (for retail electric operations) or through cost of service rates (for gas operations). For retail electric operations, current pension expense is recognized based on amounts collected through its rate rider, and differences between actual pension expense and amounts recognized pursuant to the rider are deferred as a regulatory asset (for under-collections) or regulatory liability (for over-collections) as applicable. In addition, SCE&G amortizes certain previously deferred pension costs. See Note 2.

Other changes in plan assets and benefit obligations recognized in OCI (net of tax) were as follows:

	Pension Benefits			Other Postretirement Benefits		
Millions of dollars	2015	2014	2013	2015	2014	2013
Current year actuarial (gain) loss	$ 2.7	$ 3.1	$ (5.0)	$ (1.2)	$ 1.3	$ (1.8)
Amortization of actuarial losses	(0.4)	(0.2)	(0.5)	(0.1)	—	(0.2)
Amortization of prior service cost	(0.1)	(0.2)	(0.2)	(0.1)	—	—
Prior service cost (credit)	—	—	(0.3)	—	—	—
Amortization of transition obligation	—	—	—	—	—	(0.1)
Total recognized in OCI	$ 2.2	$ 2.7	$ (6.0)	$ (1.4)	$ 1.3	$ (2.1)

Other changes in plan assets and benefit obligations recognized in regulatory assets were as follows:

	Pension Benefits			Other Postretirement Benefits		
Millions of dollars	2015	2014	2013	2015	2014	2013
Current year actuarial (gain) loss	$ 9.2	$ 101.3	$ (157.5)	$ (18.0)	$ 19.4	$ (29.9)
Amortization of actuarial losses	(11.9)	(4.0)	(14.7)	(1.8)	—	(2.7)
Amortization of prior service cost	(3.7)	(3.2)	(5.2)	(0.3)	(0.3)	(0.6)
Prior service cost (credit)	—	—	(8.9)	—	—	—
Amortization of transition obligation	—	—	—	—	—	(0.2)
Total recognized in regulatory assets	$ (6.4)	$ 94.1	$ (186.3)	$ (20.1)	$ 19.1	$ (33.4)

Significant Assumptions Used in Determining Net Periodic Benefit Cost

	Pension Benefits			Other Postretirement Benefits		
	2015	2014	2013	2015	2014	2013
Discount rate	4.20%	5.03%	4.10%/5.07%	4.30%	5.19%	4.19%
Expected return on plan assets	7.50%	8.00%	8.00%	n/a	n/a	n/a
Rate of compensation increase	3.00%	3.00%	3.75%/3.00%	3.00%	3.75%	3.75%
Health care cost trend rate	n/a	n/a	n/a	7.00%	7.40%	7.80%
Ultimate health care cost trend rate	n/a	n/a	n/a	5.00%	5.00%	5.00%
Year achieved	n/a	n/a	n/a	2020	2020	2020

Net periodic benefit cost for the period through September 1, 2013 was determined using a 4.10% discount rate, and net periodic benefit cost after that date was determined using a 5.07% discount rate. Similarly, estimated rates of compensation increase were changed in connection with the September 1, 2013 remeasurement.

The estimated amounts to be amortized from accumulated other comprehensive loss into net periodic benefit cost in 2016 are as follows:

Millions of Dollars	Pension Benefits	Other Postretirement Benefits
Actuarial loss	$ 0.6	—
Prior service cost	0.2	—
Total	$ 0.8	—

The estimated amounts to be amortized from regulatory assets into net periodic benefit cost in 2016 are as follows:

Millions of Dollars	Pension Benefits	Other Postretirement Benefits
Actuarial loss	$ 12.7	$ 0.3
Prior service cost	3.4	0.3
Total	$ 16.1	$ 0.6

Other postretirement benefit costs are subject to annual per capita limits pursuant to the plan's design. As a result, the effect of a one-percent increase or decrease in the assumed health care cost trend rate on total service and interest cost is not significant.

401(k) Retirement Savings Plan

The Company sponsors a defined contribution plan in which eligible employees may defer up to 75% of eligible earnings subject to certain limits and may diversify their investments. Employee deferrals are fully vested and nonforfeitable at all times. The Company provides 100% matching contributions up to 6% of an employee's eligible earnings. Total matching contributions made to the plan were $26.2 million in 2015, $25.8 million in 2014 and $23.4 million in 2013 and were made in the form of SCANA common stock.

9. SHARE-BASED COMPENSATION

The LTECP provides for grants of nonqualified and incentive stock options, stock appreciation rights, restricted stock, performance shares, performance units and restricted stock units to certain key employees and non-employee directors. The LTECP currently authorizes the issuance of up to five million shares of SCANA's common stock, no more than one million of which may be granted in the form of restricted stock.

Compensation cost is measured based on the grant-date fair value of the instruments issued and is recognized over the period that an employee provides service in exchange for the award. Share-based payment awards do not have non-forfeitable rights to dividends or dividend equivalents. To the extent that the awards themselves do not vest, dividends or dividend equivalents which would have been paid on those awards do not vest.

The 2013-2015 and 2014-2016 performance cycles provide for performance measurement and award determination on an annual basis, with payment of awards being deferred until after the end of the three-year performance cycle. The 2015-2017 award is based on performance over a single three-year cycle. In each performance cycle of the 2013-2015 and 2014-2016 awards, 20% of the performance awards were granted in the form of restricted share units, which are liability awards payable in cash and 80% of the awards were granted in performance shares, each of which has a value that is equal to, and changes with, the value of a share of SCANA common stock. For the 2015-2017 awards, 30% are in the form of restricted share units and 70% are in the form of performance shares. Dividend equivalents are accrued on the performance shares and the restricted share units. Performance awards and related dividend equivalents are subject to forfeiture in the event of termination of employment prior to the end of the cycle, subject to certain exceptions. Payouts of performance share awards are determined by SCANA's performance against pre-determined measures of TSR as compared to a peer group of utilities (weighted 50%) and growth in GAAP-adjusted net earnings per share (weighted 50%).

Compensation cost of liability awards is recognized over their respective three-year performance periods based on the estimated fair value of the award, which is periodically updated based on expected ultimate cash payout, and is reduced by estimated forfeitures. Awards under the 2013-2015 performance cycle were paid in cash totaling $18.4 million at SCANA's discretion in February 2016. Cash-settled liabilities related to earlier performance cycles totaled approximately $20.8 million in 2015, $11.8 million in 2014, and $12.2 million in 2013.

Fair value adjustments for all performance cycles resulted in compensation expense recognized in the statements of income totaling approximately $18.0 million in 2015, $20.3 million in 2014 and $8.7 million in 2013. Such fair value adjustments also resulted in capitalized compensation costs of $2.3 million in 2015, $3.1 million in 2014 and $1.4 million in 2013. At December 31, 2015, SCANA had $20.4 million of unrecognized compensation cost, which is expected to be recognized over a weighted-average period of 18 months.

10. COMMITMENTS AND CONTINGENCIES

Nuclear Insurance

Under Price-Anderson, SCE&G (for itself and on behalf of Santee-Cooper, a one-third owner of Summer Station Unit 1) maintains agreements of indemnity with the NRC that, together with private insurance, cover third-party liability arising from any nuclear incident occurring at the company's nuclear power plant. Price-Anderson provides funds up to $13.4 billion for public liability claims that could arise from a single nuclear incident. Each nuclear plant is insured against this liability to a maximum of $375 million by ANI with the remaining coverage provided by a mandatory program of deferred premiums that could be assessed, after a nuclear incident, against all owners of commercial nuclear reactors. Each reactor licensee is currently liable for up to $127.3 million per reactor owned for each nuclear incident occurring at any reactor in the United States, provided that not more than $18.9 million of the liability per reactor would be assessed per year. SCE&G's maximum assessment, based on its two-thirds ownership of Summer Station Unit 1, would be $84.8 million per incident, but not more than $12.6 million per year. Both the maximum assessment per reactor and the maximum yearly assessment are adjusted for inflation at least every five years.

SCE&G currently maintains insurance policies (for itself and on behalf of Santee Cooper) with NEIL. The policies provide coverage to

SCE&G currently maintains insurance policies (for itself and on behalf of Santee Cooper) with NEIL. The policies provide coverage to Summer Station Unit 1 for property damage and outage costs up to $2.75 billion resulting from an event of nuclear origin. In addition, a builder's risk insurance policy has been purchased from NEIL for the construction of the New Units. This policy provides the owners of the New Units up to $500 million of coverage for accidental property damage occurring during construction. The NEIL policies, in the aggregate, are subject to a maximum loss of $2.75 billion for any single loss occurrence. All of the NEIL policies permit retrospective assessments under certain conditions to cover insurer's losses. Based on the current annual premiums, SCE&G's portion of the retrospective premium assessment would not exceed $43.5 million.

To the extent that insurable claims for property damage, decontamination, repair and replacement and other costs and expenses arising from a nuclear incident at Summer Station Unit 1 exceed the policy limits of insurance, or to the extent such insurance becomes unavailable in the future, and to the extent that SCE&G rates would not recover the cost of any purchased replacement power, SCE&G will retain the risk of loss as a self-insurer. SCE&G has no reason to anticipate a serious nuclear incident. However, if such an incident were to occur, it likely would have a material impact on the Company's results of operations, cash flows and financial position.

New Nuclear Construction

In 2008, SCE&G, on behalf of itself and as agent for Santee Cooper, contracted with the Consortium for the design and construction of the New Units at the site of Summer Station. SCE&G's current ownership share in the New Units is 55%. As discussed below, SCE&G has agreed to acquire an additional 5% ownership in the New Units from Santee Cooper.

EPC Contract and BLRA Matters

The construction of the New Units and SCE&G's related recovery of financing costs through rates is subject to review and approval by the SCPSC as provided for in the BLRA. Under the BLRA, the SCPSC has approved, among other things, a milestone schedule and a capital costs estimates schedule for the New Units. This approval constitutes a final and binding determination that the New Units are used and useful for utility purposes, and that the capital costs associated with the New Units are prudent utility costs and expenses and are properly included in rates, so long as the New Units are constructed or are being constructed within the parameters of the approved milestone schedule, including specified contingencies, and the approved capital costs estimates schedule. Subject to the same conditions, the BLRA provides that SCE&G may apply to the SCPSC annually for an order to recover through revised rates SCE&G's weighted average cost of capital applied to all or part of the outstanding balance of construction work in progress concerning the New Units. Such annual rate changes are described in Note 2. As of December 31, 2015, SCE&G's investment in the New Units, including related transmission, totaled $3.6 billion, for which the financing costs on $3.2 billion have been reflected in rates under the BLRA.

The SCPSC granted initial approval of the construction schedule and related forecasted capital costs in 2009. The NRC issued COLs in March 2012. In November 2012, the SCPSC approved an updated milestone schedule and additional updated capital costs for the New Units. In addition, the SCPSC approved revised substantial completion dates for the New Units based on that March 2012 issuance of the COL and the amounts agreed upon by SCE&G and the Consortium in July 2012 to resolve known claims by the Consortium for costs related to COL delays, design modifications of the shield building and certain prefabricated structural modules for the New Units and unanticipated rock conditions at the site. In October 2014, the South Carolina Supreme Court affirmed the SCPSC's order on appeal.

Since the settlement of delay-related claims in 2012, the Consortium has continued to experience delays in the schedule. Shield building construction remains a principal focus area for SCE&G's oversight of the project. The primary critical path for both Unit 2 and Unit 3 runs through the placement of concrete within the containment vessels, the fabrication of shield building panels, the fabrication of the air inlet and tension rings and the completion of shield building construction. For Unit 3, the critical path also runs through the setting of CA20 which is a prerequisite to concrete placement in certain areas of the nuclear island. Plans to accelerate the work needed to permit placing this concrete are underway. In addition, WEC has reached agreement on a mitigation plan to accelerate shield building panel fabrication with one of its subcontractors. Additional mitigation will be required in critical path areas to support the updated substantial completion dates described below.

During the fourth quarter of 2013, the Consortium began a full re-baselining of the Unit 2 and Unit 3 construction schedules to incorporate a more detailed evaluation of the engineering and procurement activities necessary to accomplish the schedules and to provide a detailed reassessment of the impact of the revised Unit 2 and Unit 3 schedules on engineering and design resource allocations, procurement, construction work crew efficiencies, and other items. The result was a revised fully

integrated project schedule with timing of specific construction activities (Revised, Fully-Integrated Construction Schedule) along with related cost information.

The Revised, Fully-Integrated Construction Schedule indicated that the substantial completion of Unit 2 was expected to occur in mid-June 2019 and that the substantial completion of Unit 3 was expected to be approximately 12 months later. The Consortium continues to refine and update the Revised, Fully-Integrated Construction Schedule as designs are finalized, as construction progresses, and as additional information is integrated project schedule with timing of specific construction activities (Revised, Fully-Integrated Construction Schedule) along with related cost information.

The Revised, Fully-Integrated Construction Schedule indicated that the substantial completion of Unit 2 was expected to occur in mid-June 2019 and that the substantial completion of Unit 3 was expected to be approximately 12 months later. The Consortium continues to refine and update the Revised, Fully-Integrated Construction Schedule as designs are finalized, as construction progresses, and as additional information is received.

In September 2015, the SCPSC approved an updated BLRA milestone schedule based on revised substantial completion dates for Units 2 and 3 of June 2019 and June 2020, respectively, each subject to an 18-month contingency period. In addition, the SCPSC approved certain updated owner's costs ($245 million) and other capital costs ($453 million), of which $539 million were associated with the schedule delays and other contested costs. In this proceeding, SCE&G's total projected capital costs (in 2007 dollars) and gross construction cost estimates (including escalation and AFC) were estimated to be $5.2 billion and $6.8 billion, respectively. These projections included cost amounts related to the Revised, Fully-Integrated Construction Schedule for which SCE&G had not accepted responsibility and which were the subject of dispute. As such, these updated milestone schedule and projections did not reflect the resolution of negotiations. In addition, the SCPSC approved a revision to the allowed return on equity for new nuclear construction from 11.0% to 10.5%. This revised return on equity will be applied prospectively for the purpose of calculating revised rates sought by SCE&G under the BLRA on and after January 1, 2016, until such time as the New Units are completed.

On October 27, 2015, SCE&G, Santee Cooper and the Consortium reached a settlement regarding the above mentioned disputes, and the EPC Contract was amended. The October 2015 Amendment became effective in December 2015, upon the consummation of the acquisition by WEC of the stock of Stone & Webster from CB&I. Following that acquisition, Stone & Webster continues to be a member of the Consortium as a subsidiary of WEC rather than CB&I, and WEC has engaged Fluor Corporation as a subcontracted construction manager.

Among other things, the October 2015 Amendment:

(i) resolved by settlement and release substantially all outstanding disputes between SCE&G and the Consortium, in exchange for (a) an additional cost to be paid by SCE&G and Santee Cooper of $300 million (SCE&G’s 55% portion being $165 million) and an increase in the fixed component of the contract price by that amount, and (b) a credit to SCE&G and Santee Cooper of $50 million (SCE&G’s 55% portion being approximately $27 million) to be applied to the target component of the contract price,

(ii) revised the guaranteed substantial completion dates of Units 2 and 3 to August 31, 2019 and 2020, respectively,

(iii) revised the delay-related liquidated damages computation requirements, including those related to the eligibility of the New Units to earn Internal Revenue Code Section 45J production tax credits (see also below), and capped those aggregate liquidated damages at $463 million per New Unit (SCE&G’s 55% portion being approximately $255 million per New Unit),

(iv) provides for payment to the Consortium of a completion bonus of $275 million per New Unit (SCE&G’s 55% portion being approximately $151 million per New Unit) for each New Unit placed in service by the deadline to qualify for production tax credits,

(v) provides for development of a revised construction milestone payment schedule, with SCE&G and Santee Cooper making monthly payments of $100 million (SCE&G’s 55% portion being $55 million) for each of the first five months following effectiveness, followed by payments made based on milestones achieved, and

(vi) provided that SCE&G and Santee Cooper waive and cancel the CB&I parent company guaranty with respect to the project.

Under the October 2015 Amendment, SCE&G’s total estimated project costs increased by approximately $286 million over the $6.8 billion approved by the SCPSC in September 2015, bringing its total estimated gross construction cost of the project (including escalation and AFC) to approximately $7.1 billion.

The payment obligations under the EPC Contract are joint and several obligations of WEC and Stone & Webster, and in connection with the October 2015 Amendment, Toshiba Corporation, WEC’s parent company, reaffirmed its guaranty of WEC’s payment obligations. Based on Toshiba's current credit ratings and pursuant to the terms of the EPC Contract, SCE&G has exercised its rights to demand a payment and performance bond from WEC. Such bond will be based on estimated billings and its aggregate nominal coverage will not exceed $100 million (or $55 million for SCE&G's 55% share). SCE&G and Santee Cooper are responsible for the cost of the bond. In addition, the EPC Contract provides that upon the request of

SCE&G, the Consortium must escrow certain intellectual property and software for SCE&G's benefit to enable completion of the New Units. SCE&G has made such a request to the Consortium.

In addition to the above, the October 2015 Amendment provided for an explicit definition of a Change in Law designed to reduce the likelihood of certain future commercial disputes, and the Consortium also acknowledged and agreed that the project scope includes providing New Units that meet the standards of the NRC approved Design Control Document Revision 19. The October 2015 Amendment also established a

SCE&G, the Consortium must escrow certain intellectual property and software for SCE&G's benefit to enable completion of the New Units. SCE&G has made such a request to the Consortium.

In addition to the above, the October 2015 Amendment provided for an explicit definition of a Change in Law designed to reduce the likelihood of certain future commercial disputes, and the Consortium also acknowledged and agreed that the project scope includes providing New Units that meet the standards of the NRC approved Design Control Document Revision 19. The October 2015 Amendment also established a dispute resolution board process for certain commercial claims and disputes, including any dispute that might arise with respect to the development of the revised construction milestone payment schedule referred to above. The EPC Contract was also revised to eliminate the requirement or ability to bring suit before substantial completion of the project.

Finally, the October 2015 Amendment provides SCE&G and Santee Cooper an irrevocable option, until November 1, 2016 and subject to regulatory approvals, to further amend the EPC Contract to fix the total amount to be paid to the Consortium for its entire scope of work on the project (excluding a limited amount of work within the time and materials component of the contract price) after June 30, 2015 at $6.082 billion (SCE&G’s 55% portion being approximately $3.345 billion). This total amount to be paid would be subject to adjustment for amounts paid since June 30, 2015. Were this fixed price option to be exercised, the aggregate delay-related liquidated damages referred to in (iii) above would be capped at $338 million per unit (SCE&G’s 55% portion being approximately $186 million per unit), and the completion bonus referred to in (iv) above would be $150 million per New Unit (SCE&G’s 55% portion being approximately $83 million per New Unit). The exercise of this fixed price option would result in SCE&G’s total estimated project costs increasing by approximately $774 million over the $6.8 billion approved by the SCPSC in September 2015, and would bring its total estimated gross construction cost (including escalation and AFC) of the project to approximately $7.6 billion.

Resolution of the disputes as described in (i) above, or in the case of the exercise of the fixed price option, would result in estimated project costs above the amounts approved by the SCPSC; however, the guaranteed substantial completion dates fall within the SCPSC approved 18-month contingency periods. SCE&G held an allowable ex parte communication briefing with the SCPSC on November 19, 2015 and, following an evaluation as to whether to exercise the fixed price option, expects to file a petition in 2016, as provided under the BLRA, for an update to the project’s estimated capital cost and milestone schedule which would incorporate the impact of the October 2015 Amendment.

Additional claims by the Consortium or SCE&G involving the project schedule and budget may arise as the project continues. The parties to the EPC Contract have established both informal and formal dispute resolution procedures in order to resolve such issues. SCE&G expects to resolve all disputes through both the informal and formal procedures and currently anticipates that any costs that arise through such dispute resolution processes (including those reflected in the October 2015 Amendment described above), as well as other costs identified from time to time, will be recoverable through rates.

Santee Cooper Matters

As noted above, SCE&G has agreed to acquire an additional 5% ownership in the New Units from Santee Cooper. Under the terms of this agreement, SCE&G will acquire a 1% ownership interest in the New Units at the commercial operation date of Unit 2, an additional 2% ownership interest no later than the first anniversary of such commercial operation date, and the final 2% no later than the second anniversary of such commercial operation date. SCE&G has agreed to pay an amount equal to Santee Cooper's actual cost, including its cost of financing, of the percentage conveyed as of the date of each conveyance. In addition, the agreement provides that Santee Cooper will not transfer any of its remaining interest in the New Units to third parties until the New Units are complete. This transaction will not affect the payment obligations between the parties during construction for the New Units, nor is it anticipated that the payments for the additional ownership interest would be reflected in a revised rates filing under the BLRA. Based on the October 2015 Amendment, which has not been approved by the SCPSC, SCE&G’s currently projected cost would be approximately $750 million to $850 million for the additional 5% interest being acquired from Santee Cooper.

Nuclear Production Tax Credits

The IRS has notified SCE&G that, subject to a national megawatt capacity limitation, the electricity to be produced by each of the New Units (advanced nuclear units, as defined) would qualify for nuclear production tax credits under Section 45J of the Internal Revenue Code to the extent that such New Unit is operational before January 1, 2021 and other eligibility requirements are met. These nuclear production tax credits (related to SCE&G's 55% share of both New Units) could total as much as approximately $1.4 billion. Such credits would be earned over the first eight years of each New Unit's operations and would be realized by SCE&G over those years or during allowable carry-forward periods. Based on the guaranteed substantial completion dates provided above, both New Units are expected to be operational and to qualify for the nuclear production tax

credits; however, further delays in the schedule or changes in tax law could impact such conclusions. When and to the extent that production tax credits are realized, their benefits are expected to be provided directly to SCE&G's electric customers.

Other Project Matters

credits; however, further delays in the schedule or changes in tax law could impact such conclusions. When and to the extent that production tax credits are realized, their benefits are expected to be provided directly to SCE&G's electric customers.

Other Project Matters

When the NRC issued the COLs for the New Units, two of the conditions that it imposed were requiring inspection and testing of certain components of the New Units' passive cooling system, and requiring the development of strategies to respond to extreme natural events resulting in the loss of power at the New Units. In addition, the NRC directed the Office of New Reactors to issue to SCE&G an order requiring enhanced, reliable spent fuel pool instrumentation. SCE&G prepared and submitted an overall integration plan for the New Units to the NRC in August 2013. That plan is currently under review by the NRC and SCE&G does not anticipate any additional regulatory actions as a result of that review, but it cannot predict future regulatory activities or how such initiatives would impact construction or operation of the New Units.

Environmental

The Company's operations are subject to extensive regulation by various federal and state authorities in the areas of air quality, water quality, control of toxic substances and hazardous and solid wastes. Applicable statutes and rules include the CAA, CWA, Nuclear Waste Act and CERCLA, among others. In many cases, regulations proposed by such authorities could have a significant impact on the Company's financial condition, results of operations and cash flows. In addition, the Company often cannot predict what conditions or requirements will be imposed by regulatory or legislative proposals. To the extent that compliance with environmental regulations or legislation results in capital expenditures or operating costs, the Company expects to recover such expenditures and costs through existing ratemaking provisions.

From a regulatory perspective, SCANA, SCE&G and GENCO continually monitor and evaluate their current and projected emission levels and strive to comply with all state and federal regulations regarding those emissions. SCE&G and GENCO participate in the sulfur dioxide and nitrogen oxide emission allowance programs with respect to coal plant emissions and also have constructed additional pollution control equipment at several larger coal-fired electric generating plants. Further, SCE&G is engaged in construction activities of the New Units which are expected to reduce GHG emission levels significantly once they are completed and dispatched by potentially displacing some of the current coal-fired generation sources. These actions are expected to address many of the rules and regulations discussed herein.

On August 3, 2015, the EPA issued a revised standard for new power plants by re-proposing NSPS under the CAA for emissions of carbon dioxide from newly constructed fossil fuel-fired units. The final rule requires all new coal-fired power plants to meet a carbon emission rate of 1,400 pounds carbon dioxide per MWh and new natural gas units to meet 1,000 pounds carbon dioxide per MWh. While most new natural gas plants will not be required to include any new technologies, no new coal-fired plants could be constructed without partial carbon capture and sequestration capabilities. The Company is evaluating the final rule, but does not plan to construct new coal-fired units in the foreseeable future.

In addition, on August 3, 2015, the EPA issued its final rule on emission guidelines for states to follow in developing plans to address GHG emissions from existing units. The rule includes state-specific goals for reducing national carbon dioxide emissions by 32% from 2005 levels by 2030. The rule also provides for nuclear reactors under construction, such as the New Units, to count towards compliance and establishes a phased-in compliance approach beginning in 2022. The rule gives states from one to three years to issue SIPs, which will ultimately define the specific compliance methodology that will be applied to existing units in that state. It is expected that South Carolina will request a two-year extension (until September 2018). On February 9, 2016, the Supreme Court stayed the rule pending disposition of a petition of review of the rule in the Court of Appeals. The order of the Supreme Court has no immediate impact on SCE&G and GENCO or their generation operations. The Company is currently evaluating the rule and expects any costs incurred to comply with such rule to be recoverable through rates.

In July 2011, the EPA issued the CSAPR to reduce emissions of sulfur dioxide and nitrogen oxide from power plants in the eastern half of the United States. A series of court actions stayed this rule until October 23, 2014, when the Court of Appeals granted a motion to lift the stay. On December 3, 2014, the EPA published an interim final rule that aligns the dates in the CSAPR text with the revised court-ordered schedule, which delayed the implementation dates to 2015 for Phase 1 and to 2017 for Phase 2. The CSAPR replaces the CAIR and requires a total of 28 states to reduce annual sulfur dioxide emissions and annual or ozone season nitrogen oxide emissions to assist in attaining the ozone and fine particle NAAQS. The rule establishes an emissions cap for sulfur dioxide and nitrogen oxide and limits the trading for emission allowances by separating affected states into two groups with no trading between the groups. On July 28, 2015, the Court of Appeals held that Phase 2 emissions budgets for certain states, including South Carolina, required reductions in emissions beyond the point necessary to achieve downwind attainment and were, therefore, invalid. The Court of Appeals remanded CSAPR, without vacating the rule, to the

EPA for further consideration. The opinion of the Court of Appeals has no immediate impact on SCE&G and GENCO or their generation operations. Air quality control installations that SCE&G and GENCO have already completed have positioned them to comply with the existing allowances set by the CSAPR. Any cost incurred to comply with CSAPR are expected to be recoverable through rates.

In April 2012, the EPA's MATS rule containing new standards for mercury and other specified air pollutants became effective. The rule provides up to four years for generating facilities to meet the standards, and the Company's evaluation of the rule is ongoing. The Company's decision to retire certain coal-fired units (see Note 2) and its project to build the New Units along with other actions are expected to result in the

EPA for further consideration. The opinion of the Court of Appeals has no immediate impact on SCE&G and GENCO or their generation operations. Air quality control installations that SCE&G and GENCO have already completed have positioned them to comply with the existing allowances set by the CSAPR. Any cost incurred to comply with CSAPR are expected to be recoverable through rates.

In April 2012, the EPA's MATS rule containing new standards for mercury and other specified air pollutants became effective. The rule provides up to four years for generating facilities to meet the standards, and the Company's evaluation of the rule is ongoing. The Company's decision to retire certain coal-fired units (see Note 2) and its project to build the New Units along with other actions are expected to result in the Company's compliance with MATS.

On November 19, 2014, the EPA finalized its reconsideration of certain provisions applicable during startup and shutdown of generating facilities under the MATS rule. SCE&G and GENCO have received a one year extension (until April 2016) to comply with MATS at Cope, McMeekin, Wateree and Williams Stations. These extensions will allow time to convert McMeekin Station to burn natural gas and to install additional pollution control devices at the other plants that will enhance the control of certain MATS-regulated pollutants. On June 29, 2015, the U.S. Supreme Court ruled that the EPA unreasonably failed to consider costs in its decision to regulate, and remanded a case challenging the regulation on that basis to the Court of Appeals. The Court noted during remand that EPA has said that it is on track to issue a revised "appropriate and necessary" finding by April 15, 2016. The ruling, however, is not expected to have an impact on SCE&G or GENCO due to the aforementioned retirements and conversions. SCE&G and GENCO currently are in compliance with the MATS rule and expect to remain in compliance.

The CWA provides for the imposition of effluent limitations that require treatment for wastewater discharges. Under the CWA, compliance with applicable limitations is achieved under state-issued NPDES permits. As a facility's NPDES permit is renewed (every five years), any new effluent limitations would be incorporated. The ELG Rule became effective on January 4, 2016. After this date, state regulators will modify facility NPDES permits to match more restrictive standards, thus requiring facilities to retrofit with new wastewater treatment technologies. Compliance dates will vary by type of wastewater, and some will be based on a facility's five year permit cycle and thus may range from 2018 to 2023. The Company expects that wastewater treatment technology retrofits will be required at Williams and Wateree Stations and may be required at other facilities. Any costs incurred to comply with the ELG Rule are expected to be recoverable through rates.

The CWA Section 316(b) Existing Facilities Rule became effective in October 2014. This rule establishes national requirements for the location, design, construction and capacity of cooling water intake structures at existing facilities that reflect the best technology available for minimizing the adverse environmental impacts of impingement and entrainment. SCE&G and GENCO are conducting studies and implementing plans to ensure compliance with this rule. In addition, Congress is expected to consider further amendments to the CWA. Such legislation may include toxicity-based standards as well as limitations to mixing zones.

On April 17, 2015, the EPA's final rule for CCR was published in the Federal Register and became effective in the fourth quarter of 2015. This rule regulates CCR as a non-hazardous waste under Subtitle D of the Resource Conservation and Recovery Act and imposes certain requirements on ash storage ponds and other CCR management facilities at SCE&G's and GENCO's coal-fired generating facilities. Although the full effects of this rule are still being evaluated, SCE&G and GENCO have already closed or have begun the process of closure of all of their ash storage ponds and have previously recognized AROs for such ash storage ponds under existing requirements. The Company does not expect the incremental compliance costs associated with this rule to be significant and expects to recover such costs in future rates.

The Nuclear Waste Act required that the United States government accept and permanently dispose of high-level radioactive waste and spent nuclear fuel by January 31, 1998, and it imposed on utilities the primary responsibility for storage of their spent nuclear fuel until the repository is available. SCE&G entered into a Standard Contract for Disposal of Spent Nuclear Fuel and/or High-Level Radioactive Waste with the DOE in 1983. As of December 31, 2015, the federal government has not accepted any spent fuel from Summer Station Unit 1, and it remains unclear when the repository may become available. SCE&G has on-site spent nuclear fuel storage capability in its existing fuel pool until at least 2017 and has constructed a dry cask storage facility to accommodate the spent nuclear fuel output for the life of Summer Station Unit 1. SCE&G may evaluate other technology as it becomes available.

The provisions of CERCLA authorize the EPA to require the clean-up of hazardous waste sites. The states of South Carolina and North Carolina have similar laws. The Company maintains an environmental assessment program to identify and evaluate current and former operations sites that could require clean-up. In addition, regulators from the EPA and other federal or state agencies periodically notify the Company that it may be required to perform or participate in the investigation and

remediation of a hazardous waste site. As site assessments are initiated, estimates are made of the amount of expenditures, if any, deemed necessary to investigate and remediate each site. These estimates are refined as additional information becomes available; therefore, actual expenditures may differ significantly from the original estimates. Amounts estimated and accrued to date for site assessments and clean-up relate solely to regulated operations. Such amounts are recorded in regulatory assets and amortized, with recovery provided through rates.

SCE&G is responsible for four decommissioned MGP sites in South Carolina which contain residues of by-product chemicals. These sites remediation of a hazardous waste site. As site assessments are initiated, estimates are made of the amount of expenditures, if any, deemed necessary to investigate and remediate each site. These estimates are refined as additional information becomes available; therefore, actual expenditures may differ significantly from the original estimates. Amounts estimated and accrued to date for site assessments and clean-up relate solely to regulated operations. Such amounts are recorded in regulatory assets and amortized, with recovery provided through rates.

SCE&G is responsible for four decommissioned MGP sites in South Carolina which contain residues of by-product chemicals. These sites are in various stages of investigation, remediation and monitoring under work plans approved by DHEC and the EPA. SCE&G anticipates that major remediation activities at all these sites will continue at least through 2017 and will cost an additional $18.5 million, which is accrued in Other within Deferred Credits and Other Liabilities on the consolidated balance sheet. SCE&G expects to recover any cost arising from the remediation of MGP sites through rates. At December 31, 2015, deferred amounts, net of amounts previously recovered through rates and insurance settlements, totaled $34.8 million and are included in regulatory assets.

Claims and Litigation

The Company is subject to various claims and litigation incidental to its business operations which management anticipates will be resolved without a material impact on the Company's results of operations, cash flows or financial condition.

Operating Lease Commitments

The Company is obligated under various operating leases for rail cars, vehicles, office space, furniture and equipment. Leases expire at various dates through 2051. Rent expense totaled approximately $11.1 million in 2015, $12.3 million in 2014 and $14.8 million in 2013. Future minimum rental payments under such leases will be $10 million in 2016, $7 million in 2017, $6 million in 2018, $6 million in 2019, $3 million in 2020 and $27 million thereafter.

Guarantees

SCANA issues guarantees on behalf of its consolidated subsidiaries to facilitate commercial transactions with third parties. These guarantees are in the form of performance guarantees, primarily for the purchase and transportation of natural gas, standby letters of credit issued by financial institutions and credit support for certain tax-exempt bond issues. SCANA is not required to recognize a liability for such guarantees unless it becomes probable that performance under the guarantees will be required. SCANA believes the likelihood that it would be required to perform or otherwise incur any losses associated with these guarantees is remote; therefore, no liability for these guarantees has been recognized. To the extent that a liability subject to a guarantee has been incurred, the liability is included in the consolidated financial statements. At December 31, 2015, the maximum future payments (undiscounted) that SCANA could be required to make under guarantees totaled approximately $1.8 billion.

Asset Retirement Obligations

The Company recognizes a liability for the present value of an ARO when incurred if the liability can be reasonably estimated. Uncertainty about the timing or method of settlement of a conditional ARO is factored into the measurement of the liability when sufficient information exists, but such uncertainty is not a basis upon which to avoid liability recognition.

The legal obligations associated with the retirement of long-lived tangible assets that results from their acquisition, construction, development and normal operation relate primarily to the Company's regulated utility operations. As of December 31, 2015, the Company has recorded AROs of approximately $176 million for nuclear plant decommissioning (see Note 1) and AROs of approximately $344 million for other conditional obligations primarily related to generation, transmission and distribution properties, including gas pipelines. All of the amounts recorded are based upon estimates which are subject to varying degrees of imprecision, particularly since such payments will be made many years in the future.

A reconciliation of the beginning and ending aggregate carrying amount of AROs is as follows:

Millions of dollars	2015	2014
Beginning balance	$ 563	$ 576
Liabilities incurred	—	3
Liabilities settled	(16)	(6)
Accretion expense	25	26
Revisions in estimated cash flows	(52)	(36)
Ending balance	$ 520	$ 563

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Millions of dollars	**2015**	**2014**
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Liabilities incurred	—	3
Liabilities settled	(16)	(6)
Accretion expense	25	26
Revisions in estimated cash flows	(52)	(36)
Ending balance	$ 520	$ 563

In 2015, revisions in estimated cash flows primarily relate to changes in the expected timing of ARO settlements due to changes in the estimated useful lives of certain electric utility properties identified as part of a customary depreciation study. In 2014 such revisions primarily relate to lower estimates for certain environmental clean up obligations at generation facilities.

11. AFFILIATED TRANSACTIONS

The Company received cash distributions from equity-method investees of $4.0 million in 2015, $7.8 million in 2014 and $10.4 million in 2013. The Company made investments in equity-method investees of $4.1 million in 2015, $5.7 million in 2014 and $5.2 million in 2013.

SCE&G owns 40% of Canadys Refined Coal, LLC, which is involved in the manufacturing and sale of refined coal to reduce emissions. SCE&G accounts for this investment using the equity method. SCE&G's total purchases from this affiliate were $233.2 million in 2015, $260.3 million in 2014 and $134.2 million in 2013. SCE&G's total sales to this affiliate were $232.0 million in 2015, $259.0 million in 2014 and $133.6 million in 2013. SCE&G's payable to this affiliate was $12.9 million at December 31, 2015 and $27.9 million at December 31, 2014 SCE&G's receivable from this affiliate was $12.8 million at December 31, 2015 and $27.8 million at December 31, 2014.

12. SEGMENT OF BUSINESS INFORMATION

Reportable segments, which are described below, follow the same accounting policies as those described in Note 1 and reflect the effect of certain reclassifications described therein. The Company records intersegment sales and transfers of electricity and gas based on rates established by the appropriate regulatory authority. Nonregulated sales and transfers are recorded at current market prices.

Electric Operations primarily generates, transmits and distributes electricity, and is regulated by the SCPSC and FERC.

Gas Distribution, comprised of the local distribution operations of SCE&G and PSNC Energy, purchases and sells natural gas, primarily at retail. SCE&G and PSNC Energy are regulated by the SCPSC and the NCUC, respectively.

Retail Gas Marketing markets natural gas in Georgia and is regulated as a marketer by the GPSC. Energy Marketing markets natural gas to industrial and large commercial customers and municipalities in the Southeast.

All Other is comprised of the holding company and its other direct and indirect wholly-owned subsidiaries, which conduct nonregulated, energy-related operations. All Other also includes two additional subsidiaries prior to their sale in the first quarter of 2015 (see Note 13) and, in 2015, also includes within net income the holding company's gains on the sales of those businesses. None of these subsidiaries met the quantitative thresholds for determining reportable segments during any period reported.

Regulated reportable segments share a similar regulatory environment and, in some cases, overlapping service areas. However, Electric Operations' product differs from the other segments, as does its generation process and method of distribution. Marketing segments differ from each other in their respective markets and customer type.

Management uses operating income to measure segment profitability for SCE&G and other regulated operations and evaluates utility plant, net, for segments attributable to SCE&G. As a result, the Company does not allocate interest charges, income tax expense or assets other than utility plant to its segments. For nonregulated operations, management uses net income as the measure of segment profitability and evaluates total assets for financial position. Interest income is not reported by

segment and is not material. The Company's deferred tax assets are netted with deferred tax liabilities for consolidated reporting purposes.

The consolidated financial statements report operating revenues which are comprised of the energy-related and regulated segments. Revenues from non-reportable and nonregulated segments are included in Other Income. Therefore the adjustments to total operating revenues remove revenues from non-reportable segments. Adjustments to net income consist of the unallocated net income of the Company's regulated segment and is not material. The Company’s deferred tax assets are netted with deferred tax liabilities for consolidated reporting purposes.

The consolidated financial statements report operating revenues which are comprised of the energy-related and regulated segments. Revenues from non-reportable and nonregulated segments are included in Other Income. Therefore the adjustments to total operating revenues remove revenues from non-reportable segments. Adjustments to net income consist of the unallocated net income of the Company's regulated reportable segments.

Segment Assets include utility plant, net for SCE&G’s Electric Operations and Gas Distribution, and all assets for PSNC Energy and the remaining segments. As a result, adjustments to assets include non-utility plant and non-fixed assets for SCE&G.

Adjustments to Interest Expense, Income Tax Expense, Expenditures for Assets and Deferred Tax Assets include primarily the totals from SCANA or SCE&G that are not allocated to the segments. Interest Expense is also adjusted to eliminate charges between affiliates. Adjustments to Depreciation and Amortization consist of non-reportable segment expenses, which are not included in the depreciation and amortization reported on a consolidated basis. Expenditures for Assets are adjusted for AFC and revisions to estimated cash flows related to AROs. Deferred Tax Assets are adjusted to net them against deferred tax liabilities on a consolidated basis.

Disclosure of Reportable Segments (Millions of dollars)

	Electric Operations	Gas Distribution	Retail Gas Marketing	Energy Marketing	All Other	Adjustments/ Eliminations	Consolidated Total
2015							
External Revenue	$ 2,551	$ 810	$ 449	$ 569	$ 5	$ (4)	$ 4,380
Intersegment Revenue	6	2	—	128	413	(549)	—
Operating Income	876	152	n/a	n/a	236	44	1,308
Interest Expense	17	23	1	—	1	276	318
Depreciation and Amortization	277	77	2	—	16	(14)	358
Income Tax Expense	9	32	12	6	1	333	393
Net Income	n/a	n/a	19	9	185	533	746
Segment Assets	10,883	2,606	106	95	998	2,458	17,146
Expenditures for Assets	1,087	203	—	2	15	(154)	1,153
Deferred Tax Assets	5	29	9	6	—	(49)	—
2014							
External Revenue	$ 2,622	$ 1,012	$ 515	$ 786	$ 37	$ (21)	$ 4,951
Intersegment Revenue	7	2	—	196	437	(642)	—
Operating Income	768	159	n/a	n/a	27	53	1,007
Interest Expense	19	22	1	—	5	265	312
Depreciation and Amortization	300	72	2	—	24	(14)	384
Income Tax Expense	7	33	16	3	12	177	248
Net Income (Loss)	n/a	n/a	26	5	(6)	513	538
Segment Assets	10,182	2,487	140	150	1,474	2,385	16,818
Expenditures for Assets	936	200	—	2	52	(98)	1,092
Deferred Tax Assets	11	29	11	9	15	(75)	—
2013							
External Revenue	$ 2,423	$ 942	$ 465	$ 652	$ 40	$ (27)	$ 4,495
Intersegment Revenue	6	1	—	167	416	(590)	—
Operating Income	679	153	n/a	n/a	27	51	910
Interest Expense	19	22	1	—	4	251	297

Disclosure of Reportable Segments (Millions of dollars)

	Electric Operations	Gas Distribution	Retail Gas Marketing	Energy Marketing	All Other	Adjustments/ Eliminations	Consolidated Total
2015							
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Intersegment Revenue	6	2	—	128	413	(549)	—
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Expenditures for Assets	1,087	203	—	2	15	(154)	1,153
Deferred Tax Assets	5	29	9	6	—	(49)	—
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Intersegment Revenue	7	2	—	196	437	(642)	—
Operating Income	768	159	n/a	n/a	27	53	1,007
Interest Expense	19	22	1	—	5	265	312
Depreciation and Amortization	300	72	2	—	24	(14)	384
Income Tax Expense	7	33	16	3	12	177	248
Net Income (Loss)	n/a	n/a	26	5	(6)	513	538
Segment Assets	10,182	2,487	140	150	1,474	2,385	16,818
Expenditures for Assets	936	200	—	2	52	(98)	1,092
Deferred Tax Assets	11	29	11	9	15	(75)	—
2013							
External Revenue	$ 2,423	$ 942	$ 465	$ 652	$ 40	$ (27)	$ 4,495
Intersegment Revenue	6	1	—	167	416	(590)	—
Operating Income	679	153	n/a	n/a	27	51	910
Interest Expense	19	22	1	—	4	251	297
Depreciation and Amortization	297	70	3	—	26	(18)	378
Income Tax Expense	6	33	15	4	14	151	223
Net Income (Loss)	n/a	n/a	24	6	(2)	443	471
Segment Assets	9,488	2,340	172	133	1,378	1,616	15,127
Expenditures for Assets	907	140	—	1	31	27	1,106
Deferred Tax Assets	10	27	8	2	14	(61)	—

13. DISPOSITIONS

In December 2014, SCANA entered into definitive agreements to sell CGT and SCI. CGT was an interstate natural gas pipeline regulated by FERC that transported natural gas in South Carolina and southeastern Georgia, and it was sold to Dominion Resources, Inc. SCI provided fiber optic communications and other services and built, managed and leased communications towers in several southeastern states, and it was sold to Spirit Communications. These sales closed in the first quarter of 2015. Proceeds from these sales, net of transaction costs, were approximately $647 million, and the pre-tax gain on the sales recognized during 2015 was approximately $341 million.

CGT and SCI operated principally in wholesale markets, whereas the Company's primary focus is the delivery of energy-related products and services to retail markets. In addition, neither CGT nor SCI met accounting criteria for disclosure as a reportable segment. Accordingly, segment disclosures related to them are included within All Other in Note 12. As a result, the Company determined that the sales of CGT and SCI did not represent a strategic shift that had a major effect on its operations, and therefore, these sales did not meet the criteria for classification as discontinued operations.

The carrying values of the major classes of assets and liabilities classified as held for sale in the consolidated balance sheet as of December 31, 2014, were as follows:

Millions of dollars	CGT	SCI	Total
Assets Held for Sale			
Utility Plant, Net	$ 288.4	—	$ 288.4
Nonutility Property and Investments, Net	0.6	$ 40.1	40.7
Current Assets	6.5	3.9	10.4
Deferred Debits and Other Assets	0.9	0.2	1.1
Total Assets Held for Sale	$ 296.4	$ 44.2	$ 340.6
Liabilities Held for Sale			
Current Liabilities	$ 3.5	$ 2.2	$ 5.7
Deferred Credits and Other Liabilities	42.9	3.1	46.0
Total Liabilities Held for Sale	$ 46.4	$ 5.3	$ 51.7

14. QUARTERLY FINANCIAL DATA (UNAUDITED)

Millions of dollars, except per share amounts	**First Quarter**	**Second Quarter**	**Third Quarter**	**Fourth Quarter**	**Annual**
2015					
Total operating revenues	$ 1,389	$ 967	$ 1,068	$ 956	$ 4,380
Operating income	586	216	292	214	1,308
Net income	400	99	149	98	746
Earnings per share	2.80	.69	1.04	.69	5.22
2014					
Total operating revenues	$ 1,590	$ 1,026	$ 1,121	$ 1,214	$ 4,951
Operating income	350	154	269	234	1,007
Net income	193	96	144	105	538
Earnings per share	1.37	.68	1.01	.73	3.79

SOUTH CAROLINA ELECTRIC & GAS COMPANY

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

OVERVIEW

SCE&G is a regulated public utility engaged in the generation, transmission, distribution and sale of electricity and in the purchase and sale, primarily at retail, and transportation of natural gas. SCE&G's business is subject to seasonal fluctuations. Generally, sales of electricity are higher during the summer and winter months because of air-conditioning and heating requirements, and sales of natural gas are greater in the winter months due to heating requirements. SCE&G's electric service territory extends into 24 counties covering nearly 17,000 square miles in the central, southern and southwestern portions of South Carolina. The service area for natural gas encompasses all or part of 36 counties in South Carolina and covers approximately 23,000 square miles.

Key Earnings Drivers and Outlook

SOUTH CAROLINA ELECTRIC & GAS COMPANY

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Key Earnings Drivers and Outlook

During 2015, economic growth continued to improve in the southeast. In SCE&G's service territory, companies announced plans during the year to invest over $1.6 billion, with the expectation of creating approximately 4,000 jobs. South Carolina's unemployment rate ended December 2015 at 5.5%, a drop of 1% over 2014, an improvement that takes on greater significance when considering that almost 80,000 more South Carolinians were employed at the end of 2015 over 2014. In addition, SCE&G's regulated businesses experienced positive customer growth year over year.

Over the next five years, key earnings drivers for SCE&G will be additions to utility rate base, consisting primarily of capital expenditures for new generating capacity, environmental facilities and system expansion. Other factors that will impact future earnings growth include the regulatory environment, customer growth and usage and the level of growth of operation and maintenance expenses and taxes.

Electric Operations

SCE&G's electric operations primarily generates electricity and provides for its transmission, distribution and sale to approximately 698,000 customers (as of December 31, 2015) in portions of South Carolina in an area covering nearly 17,000 square miles. GENCO owns a coal-fired generating station and sells electricity solely to SCE&G. Fuel Company acquires, owns, provides financing for and sells at cost to SCE&G nuclear fuel, certain fossil fuels and emission and other environmental allowances.

Operating results are primarily driven by customer demand for electricity, rates allowed to be charged to customers and the ability to control costs. Demand for electricity is primarily affected by weather, customer growth and the economy. SCE&G is able to recover the cost of fuel used in electric generation through retail customers' bills, but increases in fuel costs affect electricity prices and, therefore, the competitive position of electricity against other energy sources.

Embedded in the rates charged to customers is an allowed regulatory return on equity. SCE&G's allowed return on equity in 2015 was 10.25% for non-BLRA rate base and 11.0% for BLRA-related rate base. To prevent the need for a non-BLRA base rate increase during years of peak nuclear construction, SCE&G has a stated goal of earning a return on equity for non-BLRA rate base of 9% or higher. For the year ended December 31, 2015, SCE&G's earned return on equity related to non-BLRA rate base was approximately 9.75%.

New Nuclear Construction

SCE&G, on behalf of itself and as agent for Santee Cooper, has contracted with the Consortium for the design and construction of two 1,250 MW (1,117 MW, net) nuclear generation units, which SCE&G will jointly own with Santee Cooper. SCE&G's current ownership share in the New Units is 55%, and SCE&G has agreed to acquire an additional 5% ownership from Santee Cooper in increments beginning with the commercial operation date of Unit 2. The purchase of this additional 5% ownership is expected to be funded by increased cash flows resulting from tax deductibility of depreciation associated with the New Units when they enter commercial operation.

The construction of the New Units and SCE&G's related recovery of financing costs through rates is subject to review and approval by the SCPSC as provided for in the BLRA. As of December 31, 2015, SCE&G's investment in the New Units totaled $3.6 billion, for which the financing costs on $3.2 billion have been reflected in rates under the BLRA.

In September 2015, the SCPSC approved an updated BLRA milestone schedule and certain updated owner's costs and other capital costs, some of which were associated with schedule delays and other contested costs. Also in September 2015, the SCPSC approved a revision to the allowed return on equity for new nuclear construction from 11.0% to 10.5%, to be applied prospectively for the purpose of calculating revised rates sought by SCE&G under the BLRA on and after January 1, 2016.

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On October 27, 2015, SCE&G, Santee Cooper and the Consortium reached a settlement regarding certain disputes, and the EPC Contract was amended. The October 2015 Amendment became effective on December 31, 2015, and among other things, it resolved by settlement and release substantially all outstanding disputes between SCE&G and the Consortium. The October 2015 Amendment also provides SCE&G and Santee Cooper an irrevocable option, until November 1, 2016 and subject to regulatory approvals, to further amend the EPC Contract to fix the total amount to be paid to the Consortium for its entire scope of work on the project after June 30, 2015, subject to certain exceptions.

On November 19, 2015, SCE&G held an allowable *ex parte* communication briefing with the SCPSC to describe SCE&G's settlement with the Consortium. During that briefing, the Company provided the following summary of key points related to the SCPSC's September 2015 order and the October 2015 Amendment.

	SCPSC Order #2015-661 September 2015	**October 2015 Amendment**	**Fixed Price Option Under the October 2015 Amendment**
Guaranteed Substantial Completion Dates	Unit 2 - June 2019 Unit 3 - June 2020	Unit 2 - August 2019 Unit 3 - August 2020	
Capital Cost (SCE&G's 55% share)	$5.247 billion	$5.492 billion	$6.757 billion
Future Escalation to WEC*	$794 million	$813 million	$19 million
Total Expected Project Cost (SCE&G's 55% share)	$6.827 billion	$7.113 billion	$7.601 billion
Liquidated Damages	$155 million at 100%$86 million - SCE&G	$926 million at 100% $509 million - SCE&G	$676 million at 100% $372 million - SCE&G
Bonuses	Capacity Performance Related	Completion - Capacity Performance bonus removed $550 million at 100% $303 million - SCE&G	$300 million at 100% $165 million - SCE&G
Change in Law Language	Generally defined	Explicitly defined - Formal written adoption of a new statute, regulation, requirement, or code or new NRC regulatory requirement that did not exist as of this amendment	

* The fixed price option, regardless of date of acceptance, would fix project costs and shift the risk of escalation (excluding escalation primarily on owner's and transmission costs) to WEC as of June 30, 2015. Total gross escalation recorded as of June 30, 2015 is $386 million. Under the fixed price option, total gross escalation remaining on the project is estimated to be approximately $145 million.

Following an evaluation as to whether to exercise the fixed price option, SCE&G expects to file a petition, as provided under the BLRA, for an update to the project's estimated capital cost schedule which would incorporate the impact of the October 2015 Amendment. Refer to the Exhibit Index for information on where a copy of the October 2015 Amendment is available publicly.

The information summarized above, as well as additional information on these and other related matters, is further discussed at Note 2 and Note 10 to the consolidated financial statements.

<u>Environmental</u>

EPA regulations have a significant impact on Consolidated SCE&G's electric operations. In 2015, several regulations were proposed or became final, including the following:

- On June 29, 2015, the Supreme Court ruled that the EPA unreasonably failed to consider costs in its decision to regulate mercury and other specified air pollutants under the MATS rule, but did not vacate MATS. The EPA has indicated that it expects to issue a revised rule responsive to the issue raised by the Supreme Court by April 15, 2016. SCE&G and GENCO have received a one-year extension (until April 2016) to comply with MATS at certain of their generating stations. These extensions will allow time to convert one generating station to burn natural gas and to

install additional pollution control devices at other generating stations. SCE&G and GENCO currently are in compliance with the MATS rule and expect to remain in compliance.

install additional pollution control devices at other generating stations. SCE&G and GENCO currently are in compliance with the MATS rule and expect to remain in compliance.

- A revised standard for new power plants under the CAA was proposed on August 3, 2015, and requires all new fossil fuel-fired power plants to meet the carbon dioxide emissions profile of a combined cycle natural gas plant. This rule effectively prevents construction of new coal-fired plants without partial carbon capture and sequestration capabilities.

- On August 3, 2015, the EPA issued its final rule under the Clean Power Plan that would regulate carbon dioxide emissions from existing units. This rule includes state-specific goals for reducing national carbon dioxide emissions by 32% from 2005 levels by 2030. The rule provides for nuclear reactors under construction, such as the New Units, to count towards compliance and establishes a phased-in compliance approach beginning in 2022. The rule gives states from one to three years to issue SIPs, which will ultimately define the specific compliance methodology that will be applied to existing units in that state. It is expected that South Carolina will request a two-year extension (until September 2018). On February 9, 2016, the Supreme Court stayed the rule pending disposition of a petition of review of the rule in the Court of Appeals. The order of the Supreme Court has no immediate impact on SCE&G and GENCO or their generation operations. Any costs incurred to comply with such rule are expected to be recoverable through rates.

- The CWA provides for the imposition of effluent limitations that require treatment for wastewater discharges. Under the CWA, compliance with applicable limitations is achieved in connection with the renewal (every five years) of state-issued NPDES permits. The ELG Rule became effective January 4, 2016. SCE&G and GENCO expect that wastewater treatment technology retrofits will be required at two generating stations and may be required at other facilities. The extent of the station-specific retrofits required and the related schedule for compliance will be determined in connection with each plant's NPDES permit renewal.

- New federal regulations affecting the management and disposal of CCRs became effective in the fourth quarter of 2015. Under these regulations, CCRs will not be regulated as hazardous waste. These regulations do impose certain requirements on ash storage ponds at SCE&G's and GENCO's generating facilities. These regulations are not expected to have a material effect on SCE&G and GENCO because SCE&G and GENCO have already closed or have begun the process of closure of all of their ash storage ponds.

The above environmental initiatives and similar issues are described in Environmental Matters herein and in Note 10 to the consolidated financial statements. Unless otherwise noted, Consolidated SCE&G cannot predict when regulatory rules or legislative requirements for any of these initiatives will become final, if at all, or what conditions they may impose on Consolidated SCE&G, if any. Consolidated SCE&G believes that any additional costs imposed by such regulations would be recoverable through rates.

Gas Distribution

The local distribution operations of SCE&G purchases, transports and sells natural gas to approximately 348,000 retail customers (as of December 31, 2015) in portions of South Carolina. Operating results for gas distribution are primarily influenced by customer demand for natural gas, rates allowed to be charged to customers and the ability to control costs. Embedded in the rates charged to customers is an allowed regulatory return on equity of 10.25%.

Demand for natural gas is primarily affected by weather, customer growth, the economy and the availability and price of alternate fuels. Natural gas competes with electricity, propane and heating oil to serve the heating and, to a lesser extent, other household energy needs of residential and small commercial customers. This competition is generally based on price and convenience. Large commercial and industrial customers often have the ability to switch from natural gas to an alternate fuel, such as propane or fuel oil. Natural gas competes with these alternate fuels based on price. As a result, any significant disparity between supply and demand, either of natural gas or of alternate fuels, and due either to production or delivery disruptions or other factors, will affect price and will impact SCE&G’s ability to retain large commercial and industrial customers. In addition, the production of shale gas in the United States continues to keep prices for this commodity at historic lows, and such prices are expected to continue at such levels for the foreseeable future.

RESULTS OF OPERATIONS

Net Income

Net income for Consolidated SCE&G was as follows:

Millions of dollars	2015	Change	2014	Change	2013
Net income	$ 479.5	4.8%	$ 457.7	17.1%	$ 390.8

2015 vs 2014

Net income increased primarily due to higher electric margin, higher gas distribution margin and lower depreciation expense, partially

RESULTS OF OPERATIONS

Net Income

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Millions of dollars	2015	Change	2014	Change	2013
Net income	$ 479.5	4.8%	$ 457.7	17.1%	$ 390.8

2015 vs 2014

Net income increased primarily due to higher electric margin, higher gas distribution margin and lower depreciation expense, partially offset by lower other income, higher operation and maintenance expense, higher property taxes, higher interest cost, and higher income taxes, as further described below.

2014 vs 2013

Net income increased primarily due to the effects of weather, customer growth and base rate increases under the BLRA. Higher electric and gas margins were partially offset by higher operation and maintenance expenses, higher depreciation expense, higher property taxes and higher interest expense, further described below.

Dividends Declared

Consolidated SCE&G’s Boards of Directors declared the following dividends on common stock (all of which was held by SCANA):

Declaration Date	Dividend Amount	Quarter Ended	Payment Date
February 18, 2016	$74.2 million	March 31, 2016	April 1, 2016
February 20, 2015	$70.7 million	March 31, 2015	April 1, 2015
April 30, 2015	$69.7 million	June 30, 2015	July 1, 2015
July 30, 2015	$70.5 million	September 30, 2015	October 1, 2015
October 29, 2015	$74.5 million	December 31, 2015	January 1, 2016
February 20, 2014	$64.3 million	March 31, 2014	April 1, 2014
April 24, 2014	$64.4 million	June 30, 2014	July 1, 2014
July 31, 2014	$68.5 million	September 30, 2014	October 1, 2014
October 30, 2014	$74.4 million	December 31, 2014	January 1, 2015

When a dividend payment date falls on a weekend or holiday, the payment is made the following business day.

Electric Operations

Electric Operations is comprised of the electric operations of SCE&G, GENCO and Fuel Company. Electric operations sales margin (including transactions with affiliates) was as follows:

Millions of dollars	2015	Change	2014	Change	2013
Operating revenues	$ 2,557.1	(2.7)%	$ 2,629.4	8.2%	$ 2,430.5
Less: Fuel used in electric generation	660.6	(17.4)%	799.3	6.4%	751.0
Purchased power	52.1	(35.4)%	80.7	87.7%	43.0
Margin	1,844.4	5.4 %	1,749.4	6.9%	1,636.5
Other operation and maintenance expenses	509.6	0.4 %	507.5	3.6%	489.9
Depreciation and amortization	266.9	(7.8)%	289.5	0.4%	288.3
Other taxes	192.4	4.1 %	184.8	3.2%	179.0
Operating Income	$ 875.5	14.1 %	$ 767.6	13.0%	$ 679.3

2015 vs 2014

- Margin increased due to downward adjustments of $69.0 million in 2014, compared to downward adjustments of $19.7 million in 2015, pursuant to orders of the SCPSC, related to fuel cost recovery and DSM Programs. These adjustments had no effect on net income as they were fully offset by the recognition, within other income, of gains realized upon the late 2013 settlement of certain derivative interest rate contracts, lower depreciation expense upon the adoption and implementation of revised depreciation rates as a result of an updated depreciation study and the application, as a reduction to operation and maintenance expenses, of a portion of the storm damage reserve. Margin also increased due to base rate increases under the BLRA of $65.7 million and residential and commercial customer growth of $21.4 million. These increases were partially offset by $25.6 million due to the effects of weather, lower industrial margins of $14.6 million primarily due to variable price contracts, and lower collections under the rate rider for pension costs of $3.0 million. See Note 2 to the consolidated financial statements.
- Operations and maintenance expenses increased due to the application of $5.0 million in 2014 of the storm damage reserve to offset downward revenue adjustments related to DSM Programs and the amortization of $3.7 million of DSM Programs cost. These increases were partially offset by lower labor costs of $2.0 million primarily due to lower pension cost recognition as a result of lower rate rider collections.
- Depreciation and amortization decreased by $28.7 million in 2015 due to the implementation of the above mentioned revised depreciation rates, $14.5 million of which was offset by downward revenue adjustments. This decrease in depreciation expense was partially offset by increases associated with net plant additions.
- Other taxes increased due primarily to higher property taxes associated with net plant additions.

2014 vs 2013

- Electric margin increased due to the effects of weather of $43.5 million, base rate increases under the BLRA of $54.1 million and customer growth of $14.7 million. These margin increases were partially offset by downward adjustments of $69.0 million in 2014, compared to downward adjustments of $50.1 million in 2013, pursuant to SCPSC orders related to fuel cost recovery, the reversal of undercollected amounts related to SCE&G's eWNA program (the eWNA was discontinued effective with the first billing cycle of 2014) and DSM Programs. Such adjustments are fully offset by the recognition within other income of gains realized upon the late 2013 settlement of certain derivative interest rate contracts and the application, as a reduction to operation and maintenance expenses, of a portion of the storm damage reserve, both of which had been deferred in regulatory accounts. See Note 2 to the consolidated financial statements.
- Operations and maintenance expenses increased due to nonlabor operating expenses of $8.9 million, DSM Programs cost amortization of $2.1 million, higher labor expense of $1.1 million which includes incentive compensation and lower pension cost recognition, storm expenses of $1.1 million and other general expenses of $1.9 million.
- Depreciation and amortization increased due to net plant additions.
- Other taxes increased due primarily to higher property taxes associated with net plant additions.

Sales volumes (in GWh) related to the electric margin above, by class, were as follows:

Classification	**2015**	**Change**	**2014**	**Change**	**2013**
Residential	7,978	(2.2)%	8,156	7.7	7,571
Commercial	7,386	0.2 %	7,371	2.3%	7,205
Industrial	6,201	(0.5)%	6,234	3.9%	6,000
Other	595	(0.8)%	600	3.3%	581
Total retail sales	22,160	(0.9)%	22,361	4.7%	21,357
Wholesale	942	(1.7)%	958	0.3%	955
Total	23,102	(0.9)%	23,319	4.5%	22,312

2015 vs 2014

Retail sales volumes decreased primarily due to the effects of weather, partially offset by customer growth.

2014 vs 2013

Retail sales volumes increased primarily due to the effects of weather and customer growth.

Gas Distribution

Gas Distribution is comprised of the local distribution operations of SCE&G. Gas distribution sales margin (including transactions with affiliates) was as follows:

Gas Distribution

Gas Distribution is comprised of the local distribution operations of SCE&G. Gas distribution sales margin (including transactions with affiliates) was as follows:

Millions of dollars	2015	Change	2014	Change	2013
Operating revenues	$ 372.7	(19.4)%	$ 462.2	11.5%	$ 414.4
Less: Gas purchased for resale	192.5	(32.0)%	283.1	16.0%	244.1
Margin	180.2	0.6 %	179.1	5.2%	170.3
Other operation and maintenance expenses	69.8	3.1 %	67.7	1.7%	66.6
Depreciation and amortization	26.8	4.3 %	25.7	2.4%	25.1
Other taxes	24.9	7.8 %	23.1	9.0%	21.2
Operating Income	$ 58.7	(6.2)%	$ 62.6	9.1%	$ 57.4

2015 vs 2014

- Margin increased by $4.3 million due to customer growth partially offset by a decrease of $3.1 million due to a SCPSC-approved decrease in base rates under the RSA which became effective in November 2014.
- Operation and maintenance expenses increased due to higher labor costs of $1.1 million, primarily due to incentive compensation.
- Depreciation and amortization increased due to net plant additions.
- Other taxes increased due primarily to higher property taxes associated with net plant additions.

2014 vs 2013

- Margin increased primarily due to residential and commercial customer growth of $4.0 million and increased average usage of $2.5 million.
- Operations and maintenance expense increased $1.3 million due to labor.
- Depreciation and amortization increased due to net plant additions.
- Other taxes increased due primarily to higher property taxes associated with net plant additions.

Sales volumes (in MMBTU) by class, including transportation gas, were as follows:

Classification (in thousands)	2015	Change	2014	Change	2013
Residential	12,086	(19.0)%	14,917	19.2 %	12,515
Commercial	12,580	(9.7)%	13,936	9.0 %	12,786
Industrial	17,901	(2.2)%	18,307	(10.3)%	20,411
Transportation gas	4,781	11.5 %	4,286	(10.7)%	4,801
Total	47,348	(8.0)%	51,446	1.8 %	50,513

2015 vs 2014

Residential and commercial firm sales volumes decreased due to the effects of weather and lower average use. These decreases were partially offset by customer growth. Commercial and industrial interruptible volumes decreased due to a shift to transportation service from system supply and the impact of curtailments. Transportation volumes increased due to customers shifting to transportation only service.

2014 vs 2013

Residential and commercial sales volumes increased primarily due to the effects of weather and customer growth. Industrial sales volumes decreased due to weather related curtailments and a customer switching to an alternative fuel source. Transportation sales volumes decreased due to weather related curtailments.

Other Operating Expenses

Other operating expenses (including transactions with affiliates) were as follows:

Millions of dollars	2015	Change	2014	Change	2013
Other operation and maintenance	$ 579.4	0.7 %	$ 575.2	3.4%	$ 556.5
Depreciation and amortization	293.7	(6.8)%	315.2	0.6%	313.4

Other Operating Expenses

Other operating expenses (including transactions with affiliates) were as follows:

Millions of dollars	2015	Change	2014	Change	2013
Other operation and maintenance	$ 579.4	0.7 %	$ 575.2	3.4%	$ 556.5
Depreciation and amortization	293.7	(6.8)%	315.2	0.6%	313.4
Other taxes	217.3	4.5 %	207.9	3.8%	200.2

Changes in other operating expenses are addressed in the electric operations and gas distribution segments.

Net Periodic Benefit Cost

Net periodic benefit cost was recorded on Consolidated SCE&G's income statements and balance sheets as follows:

Millions of dollars	2015	Change	2014	Change	2013
Income Statement Impact:					
Employee benefit costs	$ 2.8	(30.0)%	$ 4.0	(63.6)%	$ 11.0
Other expense	0.2	100.0 %	0.1	(83.3)%	0.6
Balance Sheet Impact:					
Increase in capital expenditures	3.4	*	0.3	(95.3)%	6.4
Component of amount receivable from Summer Station co-owner	1.5	*	0.1	(96.0)%	2.5
Increase (decrease) in regulatory assets	6.2	*	(3.2)	*	5.5
Net periodic benefit cost	$ 14.1	*	$ 1.3	(96.0)%	$ 26.0

* Greater than 100%

Pursuant to regulatory orders, SCE&G recovers current pension expense through a rate rider (for retail electric operations) and through cost of service rates (for gas operations), and amortizes pension costs previously deferred in regulatory assets as further described in Note 2 and Note 8 to the consolidated financial statements. Amounts amortized were as follows:

Millions of dollars	2015	2014	2013
Retail electric operations	$ 2.0	$ 2.0	$ 2.0
Gas operations	1.0	1.0	0.2

Other Income (Expense)

Other income (expense) includes the results of certain incidental non-utility activities and AFC. AFC is a utility accounting practice whereby a portion of the cost of both equity and borrowed funds used to finance construction (which is shown on the balance sheet as construction work in progress) is capitalized. Consolidated SCE&G includes an equity portion of AFC in nonoperating income and a debt portion of AFC in interest charges (credits) as noncash items, both of which have the effect of increasing reported net income. Components of other income (expense) were as follows:

Millions of dollars	2015	Change	2014	Change	2013
Other income	$ 31.1	(61.0)%	$ 79.8	51.4%	$ 52.7
Other expense	(31.1)	(8.0)%	(33.8)	93.1%	(17.5)
AFC - equity funds	24.8	(10.5)%	27.7	10.4%	25.1

2015 vs 2014

Other income decreased due primarily to the recognition of $64.0 million of gains in 2014, compared to $5.2 million in 2015, realized upon the settlement of certain interest rate contracts previously recorded as regulatory liabilities pursuant to the SCPSC orders previously discussed. Such gain recognition was fully offset by downward adjustments to revenues reflected within electric margin and had no effect on net income (see electric margin discussion). AFC decreased due to lower AFC rates.

2014 vs 2013

Other income (expense) increased primarily due to the recognition of $64.0 million of gains realized upon the late 2013 settlement of certain interest rate derivative contracts previously recorded as regulatory liabilities pursuant to SCPSC orders previously discussed, compared to $50.1 million of such gains in 2013. Such gain recognition was fully offset by downward adjustments to revenues reflected within electric margin and had no effect on net income. Donations increased $4.6 million, equity partnership losses increased $2.3 million and AFC increased $2.6 million.

Interest Expense

Components of interest expense, net of the debt component of AFC, were as follows:

Millions of dollars	2015	Change	2014	Change	2013
Interest on long-term debt, net	$ 236.0	8.5%	$ 217.6	5.2 %	$ 206.8
Other interest expense	12.1	16.3%	10.4	(1.0)%	10.5
Total	$ 248.1	8.8%	$ 228.0	4.9 %	$ 217.3

Interest on long-term debt increased in each year primarily due to increased long-term borrowings.

Income Taxes

Income tax expense increased each year primarily due to increases in income before taxes.

LIQUIDITY AND CAPITAL RESOURCES

Consolidated SCE&G anticipates that its contractual cash obligations will be met through internally generated funds and additional short- and long-term borrowings. Consolidated SCE&G expects that, barring a future impairment of the capital markets, it has or can obtain adequate sources of financing to meet its projected cash requirements for the foreseeable future, including the cash requirements for nuclear construction and refinancing maturing long-term debt.

Consolidated SCE&G’s cash requirements arise primarily from its operational needs, funding its construction programs and payment of dividends to SCANA. The ability of Consolidated SCE&G to replace existing plant investment, to expand to meet future demand for electricity and gas and to install equipment necessary to comply with environmental regulations, will depend upon its ability to attract the necessary financial capital on reasonable terms. Consolidated SCE&G recovers the costs of providing services through rates charged to customers. Rates for regulated services are generally based on historical costs. As customer growth and inflation occur and Consolidated SCE&G continues its ongoing construction program, Consolidated SCE&G expects to seek increases in rates. Consolidated SCE&G’s future financial position and results of operations will be affected by Consolidated SCE&G’s ability to obtain adequate and timely rate and other regulatory relief.

Rating agencies consider qualitative and quantitative factors when assessing Consolidated SCE&G's credit ratings, including regulatory environment, capital structure and the ability to meet liquidity requirements. Changes in the regulatory environment or deterioration of Consolidated SCE&G's commonly monitored financial credit metrics could adversely affect Consolidated SCE&G's debt ratings. This could cause Consolidated SCE&G to pay higher interest rates on its long- and short-term indebtedness, and could limit Consolidated SCE&G's access to capital markets and liquidity.

Cash outlays for property additions and construction expenditures, including nuclear fuel, were $1.0 billion in 2015. Consolidated SCE&G’s current estimates of its capital expenditures for construction and nuclear fuel for the next three years, which are subject to continuing review and adjustment, are as follows:

Estimated Capital Expenditures

Millions of dollars	2016	2017	2018
Consolidated SCE&G - Normal			
Generation	$ 88	$ 130	$ 91
Transmission & Distribution	192	163	187

Estimated Capital Expenditures

Millions of dollars	2016	2017	2018
Consolidated SCE&G - Normal			
Generation	$ 88	$ 130	$ 91
Transmission & Distribution	192	163	187
Other	12	9	15
Gas	61	63	60
Common	3	2	4
Total Consolidated SCE&G - Normal	356	367	357
New Nuclear (including transmission)	1,166	1,013	677
Cash Requirements for Construction	1,522	1,380	1,034
Nuclear Fuel	122	80	89
Total Estimated Capital Expenditures	$ 1,644	$ 1,460	$ 1,123

Consolidated SCE&G's contractual cash obligations as of December 31, 2015 are summarized as follows:

Contractual Cash Obligations

	Payments due by period				
Millions of dollars	Total	Less than 1 year	1 - 3 years	4 - 5 years	More than 5 years
Long-term and short-term debt including interest	$ 10,850	$ 777	$ 1,425	$ 454	$ 8,194
Capital leases	16	4	9	1	2
Operating leases	26	4	4	1	17
Purchase obligations	3,468	1,735	1,621	112	—
Other commercial commitments	2,725	450	825	700	750
Total	$ 17,085	$ 2,970	$ 3,884	$ 1,268	$ 8,963

Included in the table above in purchase obligations is SCE&G's portion of a contractual agreement for the design and construction of the New Units at Summer Station. SCE&G expects to be a joint owner and share operating costs and generation output of the New Units, with SCE&G currently responsible for 55 percent. SCE&G estimates it will cost $750 million to $850 million to acquire an additional 5% ownership in the New Units and has included $750 million for this purpose in other commercial commitments. See also New Nuclear Construction in Note 10 to the consolidated financial statements.

Purchase obligations includes customary purchase orders under which SCE&G has the option to utilize certain vendors without the obligation to do so. SCE&G may terminate such arrangements without penalty.

Other commercial commitments includes estimated obligations for coal and nuclear fuel purchases. SCE&G also has a legal obligation associated with the decommissioning and dismantling of Summer Station Unit 1 and other conditional AROs that are not listed in the contractual cash obligations above. See Notes 1 and 10 to the consolidated financial statements.

Consolidated SCE&G is party to certain interest rate derivative contracts for which unfavorable market movements above certain thresholds are funded in cash. Certain of these interest rate derivative contracts are accounted for as cash flow hedges, and others are not designated as cash flow hedges but are accounted for pursuant to regulatory orders. See further discussion at ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK and Note 6 to the consolidated financial statements. At December 31, 2015, Consolidated SCE&G had posted $13 million in cash collateral related to interest rate derivative contracts.

In connection with the effectiveness of the October 2015 Amendment, SCE&G accrued within accounts payable $250 million (SCE&G's 55% share is $137.5 million) as of December 31, 2015 for the settlement and release of substantially all outstanding disputes between SCE&G and the Consortium. These amounts are not included in capital expenditures and contractual cash obligations above. See Note 10 to the consolidated financial statements.

Consolidated SCE&G has a legal obligation associated with the decommissioning and dismantling of Summer Station Unit 1 and other conditional AROs that are not listed in contractual cash obligations above. See Notes 1 and 10 to the consolidated financial statements. In addition Consolidated SCE&G has recorded liabilities for certain unrecognized tax benefits that are not included in contractual cash obligations. See Note 5 to the consolidated financial statements.

Financing Limits and Related Matters

Consolidated SCE&G's issuance of various securities, including long-term and short-term debt, is subject to customary approval or authorization by regulatory bodies including the SCPSC and FERC.

SCE&G has obtained FERC authority to issue short-term indebtedness and to assume liabilities as a guarantor(pursuant to Section 204 of the Federal Power Act). SCE&G may issue unsecured promissory notes, commercial paper and direct loans in amounts not to exceed $1.6 billion outstanding with maturity dates of one year or less, and may enter into guaranty agreements in favor of lenders, bankers, and dealers in commercial paper in amounts not to exceed $600 million. GENCO has obtained FERC authority to issue short-term indebtedness not to exceed $200 million outstanding with maturity dates of one year or less. The authority described herein will expire in October 2016.

In December 2015, the Consolidated SCE&G's existing five-year committed LOCs were amended and extended by one year. At December 31, 2015 SCE&G and Fuel Company were parties to five-year credit agreements in the amounts of $1.2 billion, (of which $500 million relates to Fuel Company) which expire in December 2020. In addition, at December 31, 2015 SCE&G was party to a three-year credit agreement in the amount of $200 million which expires in December 2018. These credit agreements are used for general corporate purposes, including liquidity support for each company's commercial paper program and working capital needs and, in the case of Fuel Company, to finance or refinance the purchase of nuclear fuel, certain fossil fuels, and emission and other environmental allowances. For a list of banks providing credit support and other information, see Note 4 to the consolidated financial statements.

As of December 31, 2015, Consolidated SCE&G had no outstanding borrowings under its $1.4 billion facilities, had approximately $420 million in commercial paper borrowings outstanding, was obligated under $.3 million in LOC-supported letters of credit, and had approximately $130 million in cash and temporary investments. Consolidated SCE&G regularly monitors the commercial paper and short-term credit markets to optimize the timing for repayment of the outstanding balance
on its draws, while maintaining appropriate levels of liquidity. Average short-term borrowings outstanding during 2015 were approximately $422 million. Short-term cash needs were met primarily through the issuance of commercial paper.

At December 31, 2015, Consolidated SCE&G's long-term debt portfolio has a weighted average maturity of approximately 23 years and bears an average cost of 5.8%. Substantially all of Consolidated SCE&G's long-term debt bears fixed interest rates or is swapped to fixed. To further preserve liquidity, Consolidated SCE&G rigorously reviews its projected capital expenditures and operating costs and adjusts them where possible without impacting safety, reliability, and core customer service.

SCE&G's Restated Articles of Incorporation do not limit the dividends that may be paid on its common stock. However, SCE&G's bond indenture contains provisions that, under certain circumstances, which SCE&G considers to be remote, could limit the payment of cash dividends on its common stock, all of which is beneficially owned by SCANA.

The Federal Power Act requires the appropriation of a portion of certain earnings from hydroelectric projects. At December 31, 2015, approximately $72.4 million of retained earnings were restricted by this requirement as to payment of cash dividends on SCE&G's common stock.

SCE&G is subject to a bond indenture dated April 1, 1993 (Mortgage) covering substantially all of its electric properties under which all of its first mortgage bonds (Bonds) have been issued. Bonds may be issued under the Mortgage in an aggregate principal amount not exceeding the sum of (1) 70% of Unfunded Net Property Additions (as therein defined), (2) the aggregate principal amount of retired Bonds and (3) cash deposited with the trustee. Bonds, other than certain Bonds issued on the basis of retired Bonds, may be issued under the Mortgage only if Adjusted Net Earnings (as therein defined) for 12 consecutive months out of the 18 months immediately preceding the month of issuance are at least twice (2.0) the annual interest requirements on all outstanding Bonds and Bonds to be outstanding (Bond Ratio). For the year ended December 31, 2015, the Bond Ratio was 5.17.

Financing Activities

During 2015, net cash inflows related to financing activities totaled approximately $54 million, primarily associated with the issuance of long-term debt and contributions from parent, partially offset by repayment of short- and long-term debt and payment of dividends.

In May 2015, SCE&G issued $500 million of 5.1% first mortgage bonds due June 1, 2065. Proceeds from this sale were used to repay short-term debt primarily incurred as a result of SCE&G's construction program, to finance capital expenditures, and for general corporate purposes.

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Investing Activities

To settle interest rate derivative contracts, SCE&G paid approximately $253 million, net, in 2015, approximately $95 million in 2014 and approximately $6 million, net, through the third quarter of 2013. During the fourth quarter of 2013, SCE&G received approximately $120 million upon the settlement of interest rate derivatives.

For additional information, see Note 4 to the consolidated financial statements.

Major tax incentives included within federal legislation resulted in the allowance of bonus depreciation for property placed in service in 2008 through 2015. These incentives, along with certain other deductions, have had a positive impact on the cash flows of Consolidated SCE&G. Bonus depreciation will also be significant for 2016 through 2019 under recent law.

Ratios of earnings to fixed charges for each of the five years ended December 31, 2015, were as follows:

December 31,	**2015**	**2014**	**2013**	**2012**	**2011**
SCE&G	3.69	3.77	3.48	3.29	3.13

NEW NUCLEAR CONSTRUCTION MATTERS

For a discussion of developments related to new nuclear construction, see Note 2 and Note 10 to the consolidated financial statements.

ENVIRONMENTAL MATTERS

Consolidated SCE&G's operations are subject to extensive regulation by various federal and state authorities in the areas of air quality, water quality, control of toxic substances and hazardous and solid wastes. Applicable statutes and rules include the CAA, CWA, Nuclear Waste Act and CERCLA, among others. In many cases, regulations proposed by such authorities could have a significant impact on Consolidated SCE&G's financial condition, results of operations and cash flows. In addition, Consolidated SCE&G often cannot predict what conditions or requirements will be imposed by regulatory or legislative proposals. To the extent that compliance with environmental regulations or legislation results in capital expenditures or operating costs, Consolidated SCE&G expects to recover such expenditures and costs through existing ratemaking provisions.

For the three years ended December 31, 2015, Consolidated SCE&G's capital expenditures for environmental control equipment at its fossil fuel generating stations totaled $41.4 million. During this same period, Consolidated SCE&G expended approximately $38.5 million for the construction and retirement of landfills and ash ponds, net of disposal proceeds. In addition, Consolidated SCE&G made expenditures to operate and maintain environmental control equipment at its fossil plants of $8.7 million in 2015, $9.1 million in 2014 and $9.2 million in 2013, which are included in other operation and maintenance expense, and made expenditures to handle waste ash, net of disposal proceeds, of $1.3 million in 2015, $1.6 million in 2014 and $3.2 million in 2013, which are included in fuel used in electric generation. In addition, included within other operation and maintenance expense is an annual amortization of $1.4 million in each of 2015, 2014 and 2013 related to SCE&G's recovery of MGP remediation costs as approved by the SCPSC. It is not possible to estimate all future costs related to environmental matters, but forecasts for capitalized environmental expenditures for Consolidated SCE&G are $15.3 million for 2016 and $88.9 million for the four-year period 2017-2020. These expenditures are included in Consolidated SCE&G's Estimated Capital Expenditures table, are discussed in Liquidity and Capital Resources, and include known costs related to the matters discussed below.

The EPA is conducting an enforcement initiative against the utilities industry related to the NSR provisions and the NSPS of the CAA. As part of the initiative, many utilities have received requests for information under Section 114 of the CAA. In addition, the DOJ, on behalf of the EPA, has taken civil enforcement action against several utilities. The primary basis for these actions is the assertion by the EPA that maintenance activities undertaken by the utilities at their coal-fired power plants constituted "major modifications" which required the installation of costly BACT. Some of the utilities subject to the actions have reached settlement. Though Consolidated SCE&G cannot predict what action, if any, the

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With the pervasive emergence of concern over the issue of global climate change as a significant influence upon the economy, SCE&G and GENCO are subject to climate-related financial risks, including those involving regulatory requirements responsive to GHG emissions, as well as those involving other potential physical impacts. Other business and financial risks arising from such climate change could also materialize. Consolidated SCE&G cannot predict all of the climate-related regulatory and physical risks nor the related consequences which might impact Consolidated SCE&G, and the following discussion should not be considered all-inclusive.

Physical effects associated with climate changes could include changes in weather patterns, such as storm frequency and intensity, and any resultant damage to Consolidated SCE&G's electric system, as well as impacts on employees and customers and on Consolidated SCE&G's supply chain and many others. Much of the service territory of SCE&G is subject to the damaging effects of Atlantic and Gulf coast hurricanes and also to the damaging impact of winter ice storms. To help mitigate the financial risks arising from these potential occurrences, SCE&G maintains insurance on certain properties. As part of its ongoing operations, SCE&G maintains emergency response and storm preparation plans and teams who receive ongoing training and related simulations, all in order to allow Consolidated SCE&G to protect its assets and to return its systems to normal reliable operation in a timely fashion following any such event.

Environmental commitments and contingencies are further described in Note 10 to the consolidated financial statements.

REGULATORY MATTERS

SCE&G, GENCO and Fuel Company are subject to the regulatory jurisdiction of the following entities for the matters noted.

Company	Regulatory Jurisdiction/Matters
SCE&G, GENCO and Fuel Company	The CFTC, under Dodd-Frank, concerning recordkeeping, reporting, and other related regulations associated with swaps, options, forward contracts, and trade options, to the extent SCE&G, GENCO and Fuel Company engage in any such activities.
SCE&G	The SEC as to the issuance of certain securities and other matters; the SCPSC as to retail electric and gas rates, service, accounting, issuance of securities (other than short-term borrowings) and other matters; the FERC as to issuance of short-term borrowings, guarantees of short-term indebtedness, certain acquisitions, wholesale electric power and transmission rates and services, and other matters; the PHMSA and the DOT as to federal pipeline safety requirements for gas distribution pipeline systems and natural gas transmission systems, respectively; and the NRC with respect to the ownership, construction, operation and decommissioning of its currently operated and planned nuclear generating facilities. NRC jurisdiction encompasses broad supervisory and regulatory powers over the construction and operation of nuclear reactors, including matters of health and safety and environmental impact. In addition, the Federal Emergency Management Agency reviews, in conjunction with the NRC, certain aspects of emergency planning relating to the operation of nuclear plants.
SCE&G and GENCO	The FERC and DOE, under the Federal Power Act, as to the transmission of electric energy in interstate commerce, the wholesale sale of electric energy, the licensing of hydroelectric projects and certain other matters, including accounting.
GENCO	The SCPSC as to the issuance of securities (other than short-term borrowings) and the FERC as to the issuance of short-term borrowings, the wholesale sale of electric energy, accounting, certain acquisitions and other matters.
Fuel Company	The SEC as to the issuance of certain securities.

Material retail rate proceedings are described in Note 2 to the consolidated financial statements. In addition, the RSA allows natural gas distribution companies in South Carolina to request annual adjustments to rates to reflect changes in revenues and expenses and changes in investment. Such annual adjustments are subject to certain qualifying criteria and review by the SCPSC.

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SCE&G's electric transmission system is subject to NERC, which develops and enforces reliability standards for the bulk power systems throughout North America. NERC is subject to oversight by FERC.

Dodd-Frank provides for substantial additional regulation of over-the-counter and security-based derivative instruments, among other things, and requires numerous rule-makings by the CFTC and the SEC to implement. SCE&G has determined that it meets the end-user exception in Dodd-Frank, with the lowest level of required regulatory reporting burden imposed by this law. SCE&G is currently complying with these enacted regulations and intends to comply with regulations enacted in the future, but cannot predict when the final regulations will be issued or what requirements they will impose.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

Following are descriptions of Consolidated SCE&G's accounting policies and estimates which are most critical in terms of reporting financial condition or results of operations.

Accounting for Rate Regulated Operations

Consolidated SCE&G's regulated operations record certain assets and liabilities that defer the recognition of expenses and revenues to future periods in accordance with accounting guidance for rate-regulated utilities. In the future, in the event of deregulation or other changes in the regulatory environment, Consolidated SCE&G may no longer meet the criteria of accounting for rate-regulated utilities, and could be required to write off its regulatory assets and liabilities. Such an event could have a material effect on the results of operations, liquidity or financial position of Consolidated SCE&G's Electric Operations and Gas Distribution segments in the period the write-off would be recorded. See Note 2 to the consolidated financial statements for a description of Consolidated SCE&G's regulatory assets and liabilities.

Consolidated SCE&G's generation assets would be exposed to considerable financial risks in a deregulated electric market. If market prices for electric generation do not produce adequate revenue streams and the enabling legislation or regulatory actions do not provide for recovery of the resulting stranded costs, Consolidated SCE&G could be required to write down its investment in those assets. Consolidated SCE&G cannot predict whether any write-downs would be necessary and, if they were, the extent to which they would affect Consolidated SCE&G's results of operations in the period in which they would be recorded. As of December 31, 2015, Consolidated SCE&G's net investments in fossil/hydro and nuclear generation assets were $2.3 billion and $4.1 billion, respectively.

In the future, as a result of deregulation or other changes in the regulatory environment or changes in accounting requirements, Consolidated SCE&G could also be required to write off its regulatory assets and liabilities. Such an event could have a material effect on Consolidated SCE&G's results of operations, liquidity or financial position in the period the write-off would be recorded.

Revenue Recognition and Unbilled Revenues

Revenues related to the sale of energy are recorded when service is rendered or when energy is delivered to customers. Because customers are billed on cycles which vary based on the timing of the actual reading of their electric and gas meters, SCE&G records estimates for unbilled revenues at the end of each reporting period. Such unbilled revenue amounts reflect estimates of the amount of energy delivered to customers for which they have not yet been billed. Such unbilled revenues reflect consideration of estimated usage by customer class, the effects of different rate schedules and, where applicable, the impact of weather normalization provisions of rate structures. The accrual of unbilled revenues in this manner properly matches revenues and related costs. As of December 31, 2015 and 2014, accounts receivable included unbilled revenues of $101.5 million and $115.8 million, respectively, compared to total revenues of $2.9 billion and $3.1 billion for the years 2015 and 2014, respectively.

Nuclear Decommissioning

Accounting for decommissioning costs for nuclear power plants involves significant estimates related to costs to be incurred many years into the future. Among the factors that could change SCE&G's accounting estimates related to

decommissioning costs are changes in technology, changes in regulatory and environmental remediation requirements, and changes in financial assumptions such as discount rates and the estimated timing of cash flows. Changes in any of these estimates could significantly impact SCE&G's financial position and cash flows (although changes in such estimates should be earnings-neutral, because these costs are expected to be collected from ratepayers).

Based on a decommissioning cost study, SCE&G's two-thirds share of estimated site-specific nuclear decommissioning costs for Summer decommissioning costs are changes in technology, changes in regulatory and environmental remediation requirements, and changes in financial assumptions such as discount rates and the estimated timing of cash flows. Changes in any of these estimates could significantly impact SCE&G's financial position and cash flows (although changes in such estimates should be earnings-neutral, because these costs are expected to be collected from ratepayers).

Based on a decommissioning cost study, SCE&G's two-thirds share of estimated site-specific nuclear decommissioning costs for Summer Station Unit 1, including both the cost of decommissioning plant components that are and are not subject to radioactive contamination, totals $696.8 million, stated in 2012 dollars. Santee Cooper is responsible for decommissioning costs related to its one-third ownership interest in Summer Station Unit 1. The cost estimate assumes that upon closure the site would be maintained for 60 years in such a manner as to allow for subsequent decontamination that would permit release for unrestricted use.

Under SCE&G's method of funding decommissioning costs, amounts collected through rates are invested in insurance policies on the lives of certain Company personnel. SCE&G transfers to an external trust fund the amounts collected through electric rates, insurance proceeds and interest thereon, less expenses. The trusteed asset balance reflects the net cash surrender value of the insurance policies and cash held by the trust. Management intends for the fund, including earnings thereon, to provide for all eventual decommissioning expenditures for Summer Station Unit 1on an after-tax basis.

Asset Retirement Obligations

Consolidated SCE&G accrues for the legal obligation associated with the retirement of long-lived tangible assets that result from the acquisition, construction, development and normal operation in accordance with applicable accounting guidance. Consolidated SCE&G recognizes obligations at present value in the period in which they are incurred, and capitalizes associated asset retirement costs as part of the carrying amount of the related long-lived assets. Because such obligations relate primarily to Consolidated SCE&G's utility operations, their recognition has no significant impact on results of operations. As of December 31, 2015, Consolidated SCE&G has recorded AROs of $176 million for nuclear plant decommissioning (as discussed above) and AROs of $312 million for other conditional obligations related to generation, transmission and distribution properties, including gas pipelines. All of the amounts are based upon estimates which are subject to varying degrees of imprecision, particularly since payments in settlement of such obligations may be made many years in the future. Changes in these estimates will be recorded over time; however, these changes in estimates are not expected to materially impact results of operations so long as the regulatory framework for utilities remains in place.

Accounting for Pensions and Other Postretirement Benefits

SCE&G participates in SCANA's noncontributory defined benefit pension plan, which covers substantially all regular, full-time employees. SCANA recognizes the funded status of its defined benefit pension plan as an asset or liability and changes in funded status as a component of net periodic benefit cost or other comprehensive income, net of tax, or as a regulatory asset as required by accounting guidance. Accounting guidance requires the use of several assumptions that impact pension cost, of which the discount rate and the expected return on assets are the most sensitive. SCANA's net pension cost of $18.0 million ($14.2 million attributable to SCE&G) recorded in 2015 reflects the use of a 4.20% discount rate derived using a cash flow matching technique, and an assumed 7.50% long-term rate of return on plan assets. SCANA believes that these assumptions and the resulting pension cost amount were reasonable. For purposes of comparison, a 25 basis point reduction in the discount rate in 2015 would have increased SCANA's pension cost by $1.9 million and increased the pension obligation by $26.8 million. Further, had the assumed long-term rate of return on assets been 7.25%, SCANA's pension cost for 2015 would have increased by $2.1 million.

The following information with respect to pension assets (and returns thereon) should also be noted.

SCANA determines the fair value of the majority of its pension assets utilizing market quotes or derives them from modeling techniques that incorporate market data. Less than 10% of assets are valued using less transparent Level 3 methods.

In developing the expected long-term rate of return assumptions, SCANA evaluates historical performance, targeted allocation amounts and expected payment terms. As of the beginning of 2015, the plan's historical 10, 15, 20 and 25 year cumulative performance showed actual returns of 6.0%, 5.4%, 8.7% and 8.8%, respectively. The 2015 expected long-term rate of return of 7.50% was based on a target asset allocation of 58% with equity managers, 33% with fixed income managers and 9% with hedge fund managers. SCANA regularly reviews such allocations and periodically rebalances the portfolio when considered appropriate. As of the beginning of 2016, the plan's historical 10, 15, 20 and 25 year cumulative performance showed actual returns of 5.3%, 4.6%, 7.2% and 8.7%, respectively. For 2016, the expected rate of return is 7.50%.

Pursuant to regulatory orders, certain previously deferred pension costs are being amortized as described in Note 2 to the consolidated financial statements. Current pension expense for electric operations is being recovered through a pension cost rider, and current pension expense related to SCE&G's gas operations is being recovered through cost of service rates.

Pension benefits are not offered to employees hired or rehired after December 31, 2013, and pension benefits for existing participants will

Pursuant to regulatory orders, certain previously deferred pension costs are being amortized as described in Note 2 to the consolidated financial statements. Current pension expense for electric operations is being recovered through a pension cost rider, and current pension expense related to SCE&G's gas operations is being recovered through cost of service rates.

Pension benefits are not offered to employees hired or rehired after December 31, 2013, and pension benefits for existing participants will no longer accrue for services performed or compensation earned after December 31, 2023. As a result, the significance of pension costs and the criticality of the related estimates to SCE&G's financial statements will continue to diminish. Further, the pension trust is adequately funded under current regulations, and management does not anticipate the need to make significant pension contributions for the foreseeable future.

In addition to pension benefits, SCE&G participates in SCANA's unfunded postretirement health care and life insurance programs which provide benefits to certain active and retired employees. SCANA accounts for the cost of the postretirement medical and life insurance benefit plan in a similar manner to that used for its defined benefit pension plan. This plan is unfunded, so no assumptions related to rate of return on assets impact the net expense recorded; however, the selection of discount rates can significantly impact the actuarial determination of net expense. SCANA used a discount rate of 4.30%, derived using a cash flow matching technique, and recorded a net cost to SCE&G of $15.8 million for 2015. Had the selected discount rate been 4.05% (25 basis points lower than the discount rate referenced above), the expense for 2015 would have been $0.6 million higher and increased the obligation by $9.5 million. Because the plan provisions include "caps" on company per capita costs, and because employees hired after December 31, 2010 are responsible for the full cost of retiree medical benefits elected by them, healthcare cost inflation rate assumptions do not materially impact the net expense recorded.

OTHER MATTERS

Off-Balance Sheet Arrangements

Consolidated SCE&G holds insignificant investments in securities and businesses ventures. Consolidated SCE&G does not engage in significant off-balance sheet financing or similar transactions, although it is party to incidental operating leases in the normal course of business, generally for office space, furniture, vehicles, equipment and rail cars.

Claims and Litigation

For a description of claims and litigation see Note 10 to the consolidated financial statements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

All financial instruments described in this section are held for purposes other than trading.

The tables below provide information about long-term debt issued by Consolidated SCE&G which is sensitive to changes in interest rates. For debt obligations, the tables present principal cash flows and related weighted average interest rates by expected maturity dates. For interest rate swaps, the figures shown reflect notional amounts, weighted average rates and related maturities. Fair values for debt represent quoted market prices. Interest rate swap agreements are valued using discounted cash flow models with independently sourced data.

December 31, 2015	**Expected Maturity Date**							
Millions of dollars	**2016**	**2017**	**2018**	**2019**	**2020**	**Thereafter**	**Total**	**Fair Value**
Long-Term Debt:								
Fixed Rate ($)	110.4	10.1	719.8	9.1	8.3	3,873.0	4,730.7	5,095.0
Average Fixed Interest Rate (%)	1.13	4.50	6.02	4.73	4.94	5.71	5.64	—
Variable Rate ($)	—	—	—	—	—	67.8	67.8	63.7
Average Variable Interest Rate (%)	—	—	—	—	—	0.03	0.03	—
Interest Rate Swaps:								
Pay Fixed/Receive Variable ($)	650.0	550.0	—	—	—	71.4	1,271.4	(49.8)
Average Pay Interest Rate (%)	2.87	2.88	—	—	—	3.28	2.90	—
Average Receive Interest Rate (%)	0.61	0.61	—	—	—	0.01	0.58	—

December 31, 2014	**Expected Maturity Date**

December 31, 2014	Expected Maturity Date							
Millions of dollars	2015	2016	2017	2018	2019	Thereafter	Total	Fair Value
Long-Term Debt:								
Fixed Rate ($)	9.9	109.4	9.0	718.6	8.1	3,379.7	4,234.8	4,999.8
Average Fixed Interest Rate (%)	4.54	1.11	4.73	5.95	4.97	5.29	5.29	—
Variable Rate ($)	—	—	—	—	—	67.8	67.8	65.2
Average Variable Interest Rate (%)	—	—	—	—	—	0.04	0.04	—
Interest Rate Swaps:								
Pay Fixed/Receive Variable ($)	950.0	100.0	—	—	—	67.8	1,117.8	(233.0)
Average Pay Interest Rate (%)	3.83	3.63	—	—	—	3.28	3.78	—
Average Receive Interest Rate (%)	0.26	0.26	—	—	—	0.04	0.24	—

While a decrease in interest rates would increase the fair value of debt, it is unlikely that events which would result in a realized loss will occur.

For further discussion of Consolidated SCE&G’s long-term debt and interest rate derivatives, see ITEM 7. MANAGEMENT’S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS — Liquidity and Capital Resources and Notes 4 and 6 to the consolidated financial statements.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholder of
South Carolina Electric & Gas Company
Cayce, South Carolina

We have audited the accompanying consolidated balance sheets of South Carolina Electric & Gas Company and affiliates (the "Company") as of December 31, 2015 and 2014, and the related consolidated statements of income, comprehensive income, cash flows, and changes in equity for each of the three years in the period ended December 31, 2015. Our audits also included the financial statement schedule listed in Part IV at Item 15. These financial statements and the financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements and financial statement schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2015 and 2014, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2015, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

/s/DELOITTE & TOUCHE LLP
Charlotte, North Carolina
February 26, 2016

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2015 and 2014, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2015, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

/s/DELOITTE & TOUCHE LLP
Charlotte, North Carolina
February 26, 2016

South Carolina Electric & Gas Company and Affiliates
Consolidated Balance Sheets

December 31, (Millions of dollars)	2015	2014
Assets		
Utility Plant In Service	$ 11,153	$ 10,650
Accumulated Depreciation and Amortization	(3,869)	(3,667)
Construction Work in Progress	3,997	3,302
Plant to be Retired, Net	—	169
Nuclear Fuel, Net of Accumulated Amortization	308	329
Utility Plant, Net ($700 and $675 related to VIEs)	11,589	10,783
Nonutility Property and Investments:		
Nonutility property, net of accumulated depreciation	68	67
Assets held in trust, net-nuclear decommissioning	115	113
Other investments	1	2
Nonutility Property and Investments, Net	184	182
Current Assets:		
Cash and cash equivalents	130	100

South Carolina Electric & Gas Company and Affiliates
Consolidated Balance Sheets

December 31, (Millions of dollars)	2015	2014
Assets		
Utility Plant In Service	$ 11,153	$ 10,650
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Plant to be Retired, Net	—	169
Nuclear Fuel, Net of Accumulated Amortization	308	329
Utility Plant, Net ($700 and $675 related to VIEs)	11,589	10,783
Nonutility Property and Investments:		
Nonutility property, net of accumulated depreciation	68	67
Assets held in trust, net-nuclear decommissioning	115	113
Other investments	1	2
Nonutility Property and Investments, Net	184	182
Current Assets:		
Cash and cash equivalents	130	100
Receivables:		
Customer, net of allowance for uncollectible accounts of $3 and $4	324	413
Affiliated companies	22	109
Other	202	111
Inventories:		
Fuel	98	131
Materials and supplies	136	129
Prepayments	92	154
Other current assets	15	99
Total Current Assets ($88 and $158 related to VIEs)	1,019	1,246
Deferred Debits and Other Assets:		
Pension asset	—	10
Regulatory assets	1,857	1,745
Other	116	112
Total Deferred Debits and Other Assets ($53 and $50 related to VIEs)	1,973	1,867
Total	$ 14,765	$ 14,078

See Notes to Consolidated Financial Statements.

December 31, (Millions of dollars)	2015	2014
Capitalization and Liabilities		
Common Stock - no par value, 40.3 million shares outstanding for all periods presented	$ 2,760	$ 2,560
Retained Earnings	2,265	2,077
Accumulated Other Comprehensive Loss	(3)	(3)
Total Common Equity	5,022	4,634
Noncontrolling interest	129	123

December 31, (Millions of dollars)	2015	2014
Capitalization and Liabilities		
Common Stock - no par value, 40.3 million shares outstanding for all periods presented	$ 2,760	$ 2,560
Retained Earnings	2,265	2,077
Accumulated Other Comprehensive Loss	(3)	(3)
Total Common Equity	5,022	4,634
Noncontrolling interest	129	123
Total Equity	5,151	4,757
Long-Term Debt, net	4,659	4,270
Total Capitalization	9,810	9,027
Current Liabilities:		
Short-term borrowings	420	709
Current portion of long-term debt	110	10
Accounts payable	469	294
Affiliated payables	113	180
Customer deposits and customer prepayments	93	61
Taxes accrued	299	170
Interest accrued	66	64
Dividends declared	75	74
Derivative financial instruments	34	208
Other	61	71
Total Current Liabilities	1,740	1,841
Deferred Credits and Other Liabilities:		
Deferred income taxes, net	1,732	1,724
Asset retirement obligations	488	536
Pension and postretirement benefits	186	195
Regulatory liabilities	635	610
Other	157	122
Other -affiliate	17	23
Total Deferred Credits and Other Liabilities	3,215	3,210
Commitments and Contingencies (Note 10)	—	—
Total	$ 14,765	$ 14,078

See Notes to Consolidated Financial Statements.

South Carolina Electric & Gas Company and Affiliates
Consolidated Statements of Income

For the Years Ended December 31, (Millions of dollars)	2015	2014	2013
Operating Revenues:			
Electric	$ 2,557	$ 2,629	$ 2,431
Gas	373	462	414
Total Operating Revenues	2,930	3,091	2,845
Operating Expenses:			
Fuel used in electric generation	661	799	751

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Consolidated Statements of Income

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Operating Revenues:			
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Gas	373	462	414
Total Operating Revenues	2,930	3,091	2,845
Operating Expenses:			
Fuel used in electric generation	661	799	751
Purchased power	52	81	43
Gas purchased for resale	193	283	244
Other operation and maintenance	579	575	557
Depreciation and amortization	294	315	313
Other taxes	217	208	200
Total Operating Expenses	1,996	2,261	2,108
Operating Income	934	830	737
Other Income (Expense):			
Other income	31	80	53
Other expenses	(31)	(34)	(18)
Interest charges, net of allowance for borrowed funds used during construction of $14, $14 and $13	(248)	(228)	(217)
Allowance for equity funds used during construction	25	28	25
Total Other Expense	(223)	(154)	(157)
Income Before Income Tax Expense	711	676	580
Income Tax Expense	231	218	189
Net Income	480	458	391
Less Net Income Attributable to Noncontrolling Interest	14	12	11
Earnings Available to Common Shareholder	$ 466	$ 446	$ 380
Dividends Declared on Common Stock	$ 285	$ 272	$ 257

See Notes to Consolidated Financial Statements.

South Carolina Electric & Gas Company and Affiliates
Consolidated Statements of Comprehensive Income

Years Ended December 31, (Millions of dollars)	2015	2014	2013
Net Income	$ 480	$ 458	$ 391
Other Comprehensive Income (Loss), net of tax:			
Deferred costs of employee benefit plans, net of tax $-, $- and $-	—	—	1
Amortization of deferred employee benefit plan costs reclassified to net income, net of tax $-, $- and $-	—	—	—
Other Comprehensive Income (Loss)	—	—	1
Total Comprehensive Income	480	458	392
Less comprehensive income attributable to noncontrolling interest	(14)	(12)	(11)
Comprehensive income available to common shareholder	$ 466	$ 446	$ 381

See Notes to Consolidated Financial Statements.

South Carolina Electric & Gas Company and Affiliates
Consolidated Statements of Cash Flows

For the Years Ended December 31, (Millions of dollars)	2015	2014	2013
Cash Flows From Operating Activities:			
Net income	$ 480	$ 458	$ 391
Adjustments to reconcile net income to net cash provided from operating activities:			
Losses from equity method investments	4	5	3
Deferred income taxes, net	8	187	29
Depreciation and amortization	294	318	315
Amortization of nuclear fuel	46	45	57
Allowance for equity funds used during construction	(25)	(28)	(25)
Carrying cost recovery	(12)	(9)	(3)
Changes in certain assets and liabilities:			
Receivables	85	51	(53)
Receivables - affiliate	16	(90)	17
Inventories	(24)	(52)	35
Prepayments	70	(89)	8
Regulatory assets	150	(350)	83
Other regulatory liabilities	1	(132)	54
Accounts payable	11	(49)	12
Accounts payable - affiliate	(17)	63	(7)
Taxes accrued	129	(53)	72
Pension and other postretirement benefits	(5)	106	(186)
Derivative financial instruments	(174)	207	(65)
Other assets	38	12	27
Other liabilities	9	50	146
Other liabilities - affiliate	(6)	(9)	(58)
Net Cash Provided From Operating Activities	1,078	641	852
Cash Flows From Investing Activities:			
Property additions and construction expenditures	(1,008)	(934)	(1,003)
Proceeds from investments and sales of assets (including derivative collateral returned)	975	275	144
Purchase of investments (including derivative collateral posted)	(887)	(381)	(116)
Payments upon interest rate derivative contract settlement	(263)	(95)	(49)
Proceeds from interest rate derivative contract settlement	10	—	163
Proceeds from investment in affiliate	71	—	—
Investment in affiliate	—	(80)	—
Net Cash Used For Investing Activities	(1,102)	(1,215)	(861)
Cash Flows From Financing Activities:			
Proceeds from issuance of long-term debt	491	294	451
Repayment of long-term debt	(11)	(48)	(251)
Dividends	(285)	(260)	(241)
Short-term borrowings, net	(289)	458	(198)
Short-term borrowings-affiliate, net	(50)	56	(22)
Contribution from parent	204	89	314
Return of capital to parent	(4)	(7)	(3)
Deferred financing costs	(2)	—	—

South Carolina Electric & Gas Company and Affiliates
Consolidated Statements of Cash Flows

For the Years Ended December 31, (Millions of dollars)	2015	2014	2013
Cash Flows From Operating Activities:			
Net income	$ 480	$ 458	$ 391
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Carrying cost recovery	(12)	(9)	(3)
Changes in certain assets and liabilities:			
Receivables	85	51	(53)
Receivables - affiliate	16	(90)	17
Inventories	(24)	(52)	35
Prepayments	70	(89)	8
Regulatory assets	150	(350)	83
Other regulatory liabilities	1	(132)	54
Accounts payable	11	(49)	12
Accounts payable - affiliate	(17)	63	(7)
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Derivative financial instruments	(174)	207	(65)
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Investment in affiliate	—	(80)	—
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Repayment of long-term debt	(11)	(48)	(251)
Dividends	(285)	(260)	(241)
Short-term borrowings, net	(289)	458	(198)
Short-term borrowings-affiliate, net	(50)	56	(22)
Contribution from parent	204	89	314
Return of capital to parent	(4)	(7)	(3)
Deferred financing costs	(2)	—	—
Net Cash Provided From Financing Activities	54	582	50

Net Increase in Cash and Cash Equivalents	30	8	41
Cash and Cash Equivalents, January 1	100	92	51
Cash and Cash Equivalents, December 31	$ 130	$ 100	$ 92
Supplemental Cash Flow Information:			
Cash paid for—Interest (net of capitalized interest of $14, $14 and $13)	$ 228	$ 210	$ 200
—Income taxes paid	89	177	92
—Income taxes received	84	—	—
Noncash Investing and Financing Activities:			
Accrued construction expenditures	230	151	100
Capital lease	6	5	4
Nuclear fuel purchase	—	—	98

See Notes to Consolidated Financial Statements.

South Carolina Electric & Gas Company and Affiliates
Consolidated Statements of Changes in Equity

	Common Stock					
Millions	**Shares**	**Amount**	**Retained Earnings**	**Accumulated Other Comprehensive Income (Loss)**	**Non-controlling Interest**	**Total Equity**
Balance at January 1, 2013	40	$ 2,167	$ 1,766	$ (4)	$ 114	$ 4,043
Earnings available for common shareholder			380		11	391
Deferred cost of employee benefit plans, net of tax $-				1		1
Total Comprehensive Income (Loss)			380	1	11	392
Capital contributions from (returned to) parent		312			(1)	311
Cash dividends declared			(250)		(7)	(257)
Balance at December 31, 2013	40	2,479	1,896	(3)	117	4,489
Earnings Available for Common Shareholder			446		12	458
Deferred Cost of Employee Benefit Plans, net of tax $-				—		—
Total Comprehensive Income (Loss)			446	—	12	458
Capital contributions from parent		81			1	82
Cash dividends declared			(265)		(7)	(272)
Balance at December 31, 2014	40	2,560	2,077	(3)	123	4,757
Earnings Available for Common Shareholder			466		14	480
Deferred Cost of Employee Benefit Plans, net of tax $-				—		—
Total Comprehensive Income			466	—	14	480
Capital contributions from parent		200			—	200
Cash dividends declared			(278)		(8)	(286)
Balance at December 31, 2015	40	$ 2,760	$ 2,265	$ (3)	$ 129	$ 5,151

See Notes to Consolidated Financial Statements.

Notes to Consolidated Financial Statements

Notes to Consolidated Financial Statements

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Organization and Principles of Consolidation

SCE&G, a public utility, is a South Carolina corporation organized in 1924 and a wholly-owned subsidiary of SCANA, a South Carolina corporation. Consolidated SCE&G engages predominantly in the generation and sale of electricity to wholesale and retail customers in South Carolina and in the purchase, sale and transportation of natural gas to retail customers in South Carolina.

SCE&G has determined that it has a controlling financial interest in GENCO and Fuel Company (which are considered to be VIEs), and accordingly, the accompanying consolidated financial statements include the accounts of SCE&G, GENCO and Fuel Company. The equity interests in GENCO and Fuel Company are held solely by SCANA, SCE&G's parent. Accordingly, GENCO's and Fuel Company's equity and results of operations are reflected as noncontrolling interest in Consolidated SCE&G's consolidated financial statements. Intercompany balances and transactions between SCE&G, Fuel Company and GENCO have been eliminated in consolidation.

GENCO owns a coal-fired electric generating station with a 605 megawatt net generating capacity (summer rating). GENCO's electricity is sold, pursuant to a FERC-approved tariff, solely to SCE&G under the terms of a power purchase agreement and related operating agreement. The effects of these transactions are eliminated in consolidation. Substantially all of GENCO's property (carrying value of approximately $491 million) serves as collateral for its long-term borrowings. Fuel Company acquires, owns and provides financing for SCE&G's nuclear fuel, certain fossil fuels and emission and other environmental allowances. See also Note 4.

Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amount of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Reclassifications

In April 2015, the FASB issued accounting guidance intended to simplify the presentation of debt issuance costs by requiring that such costs be deducted from carrying amounts related to debt when presented in the balance sheet. As permitted, Consolidated SCE&G adopted this guidance retrospectively in the fourth quarter of 2015. As a result, for 2014 $29 million of unamortized debt issuance costs were reclassified to long-term debt, and certain amounts in Note 4 and Note 12 were also reclassified for comparative periods. The effect of adoption on Consolidated SCE&G's results of operations and cash flows was not significant.

In November 2015, the FASB issued accounting guidance intended to simplify the presentation of deferred tax assets and deferred tax liabilities by netting and classifying them as noncurrent on the statement of financial position. As permitted, Consolidated SCE&G early adopted this guidance retrospectively in the fourth quarter of 2015. As a result, for 2014 $27.9 million of net deferred tax liabilities previously classified in current liabilities were reclassified to long-term liabilities. The effect of adoption on Consolidated SCE&G's results of operations and cash flows was not significant.

Utility Plant

Utility plant is stated at original cost. The costs of additions, replacements and betterments to utility plant, including direct labor, material and indirect charges for engineering, supervision and AFC, are added to utility plant accounts. The original cost of utility property retired or otherwise disposed of is removed from utility plant accounts and generally charged to accumulated depreciation. The costs of repairs and replacements of items of property determined to be less than a unit of property or that do not increase the asset's life or functionality are charged to expense.

AFC is a noncash item that reflects the period cost of capital devoted to plant under construction. This accounting practice results in the inclusion of, as a component of construction cost, the costs of debt and equity capital dedicated to construction investment. AFC is included in rate base investment and depreciated as a component of plant cost in establishing rates for utility services. Consolidated SCE&G calculated AFC using average composite rates of 5.6% for 2015, 6.5% for 2014

and 6.9% for 2013. These rates do not exceed the maximum allowable rate as calculated under FERC Order No. 561. SCE&G capitalizes interest on nuclear fuel in process at the actual interest cost incurred.

Consolidated SCE&G records provisions for depreciation and amortization using the straight-line method based on the estimated service lives of the various classes of property. In 2015, SCE&G adopted lower depreciation rates for electric and common plant, as approved by the and 6.9% for 2013. These rates do not exceed the maximum allowable rate as calculated under FERC Order No. 561. SCE&G capitalizes interest on nuclear fuel in process at the actual interest cost incurred.

Consolidated SCE&G records provisions for depreciation and amortization using the straight-line method based on the estimated service lives of the various classes of property. In 2015, SCE&G adopted lower depreciation rates for electric and common plant, as approved by the SCPSC and further described in Note 2. The composite weighted average depreciation rates for utility plant assets were 2.56% in 2015, 2.84% in 2014 and 2.94% in 2013.

SCE&G records nuclear fuel amortization using the units-of-production method. Nuclear fuel amortization is included in “Fuel used in electric generation” and recovered through the fuel cost component of retail electric rates. Provisions for amortization of nuclear fuel include amounts necessary to satisfy obligations to the DOE under a contract for disposal of spent nuclear fuel.

Jointly Owned Utility Plant

SCE&G jointly owns and is the operator of Summer Station Unit 1. In addition, SCE&G will jointly own and will be the operator of the New Units being designed and constructed at the site of Summer Station. Each joint owner provides its own financing and shares the direct expenses and generation output in proportion to its ownership of a unit. SCE&G's share of the direct expenses is included in the corresponding operating expenses on its income statement.

As of December 31,	2015		2014	
	Unit 1	New Units	Unit 1	New Units
Percent owned	66.7%	55.0%	66.7%	55.0%
Plant in service	$ 1.2 billion	—	$ 1.2 billion	—
Accumulated depreciation	$ 620.4 million	—	$ 578.3 million	—
Construction work in progress	$ 214.6 million	$ 3.4 billion	$ 199.3 million	$ 2.7 billion

For a discussion of expected cash outlays and expected in-service dates for the New Units and a description of SCE&G's agreement to acquire an additional 5% ownership in the New Units, see Note 10.

Included within other receivables on the balance sheet were amounts due to SCE&G from Santee Cooper for its share of direct expenses and construction costs for Summer Station Unit 1 and the New Units. These amounts totaled $178.8 million at December 31, 2015 and $88.9 million at December 31, 2014.

Plant to be Retired

At December 31, 2014, SCE&G expected to retire three units that are or were coal-fired by 2020, which was prior to the end of the previously estimated useful lives over which the units were being depreciated. As such, these units were identified as Plant to be Retired. Subsequently, these units were converted to be gas-fired. In the third quarter of 2015, in connection with the adoption of a customary depreciation study and related analysis (see Note 2), SCE&G determined that these units would not likely be retired by 2020, and their depreciation rates were set to recover the units' net carrying value over their respective revised useful lives. Accordingly, the net carrying value of these units is no longer classified as Plant to be Retired at December 31, 2015.

Major Maintenance

Planned major maintenance costs related to certain fossil fuel turbine equipment and nuclear refueling outages are accrued in periods other than when incurred in accordance with approval by the SCPSC for such accounting treatment and rate recovery of expenses accrued thereunder. The difference between such cumulative major maintenance costs and cumulative collections are classified as a regulatory asset or regulatory liability on the consolidated balance sheet. Other planned major maintenance is expensed when incurred.

Through 2017, SCE&G is authorized to collect $18.4 million annually through electric rates to offset certain turbine maintenance expenditures. For the years ended December 31, 2015 and 2014, SCE&G incurred $16.5 million and $19.4 million, respectively, for turbine maintenance.

Nuclear refueling outages are scheduled 18 months apart. As approved by the SCPSC, effective January 1, 2013, SCE&G accrues $1.4 million per month for its portion of the nuclear refueling outages that are scheduled for the spring of 2014

throught the spring of 2020. Total costs for 2014 were $43.7 million, of which SCE&G was responsible for $29.1 million. Total costs for 2015 were $40.2 million, of which SCE&G was responsible for $26.8 million.

throught the spring of 2020. Total costs for 2014 were $43.7 million, of which SCE&G was responsible for $29.1 million. Total costs for 2015 were $40.2 million, of which SCE&G was responsible for $26.8 million.

Nuclear Decommissioning

Based on a decommissioning cost study, SCE&G’s two-thirds share of estimated site-specific nuclear decommissioning costs for Summer Station Unit 1, including the cost of decommissioning plant components both subject to and not subject to radioactive contamination, totals $696.8 million, stated in 2012 dollars. Santee Cooper is responsible for decommissioning costs related to its one-third ownership interest in Summer Station Unit 1. The cost estimate assumes that the site will be maintained over a period of approximately 60 years in such a manner as to allow for subsequent decontamination that would permit release for unrestricted use.

Under SCE&G’s method of funding decommissioning costs, amounts collected through rates ($3.2 million pre-tax in each period presented) are invested in insurance policies on the lives of certain SCE&G and affiliate personnel. SCE&G transfers to an external trust fund the amounts collected through electric rates, insurance proceeds and interest thereon, less expenses. The trusteed asset balance reflects the net cash surrender value of the insurance policies and cash held by the trust. Management intends for the fund, including earnings thereon, to provide for all eventual decommissioning expenditures for Summer Station Unit 1 on an after-tax basis.

Cash and Cash Equivalents

Consolidated SCE&G considers temporary cash investments having original maturities of three months or less at time of purchase to be cash equivalents. These cash equivalents are generally in the form of commercial paper, certificates of deposit, repurchase agreements and treasury bills.

Receivables

Customer receivables reflect amounts due from customers arising from the delivery of energy or related services and include both billed and unbilled amounts earned pursuant to revenue recognition practices described below. Customer receivables are generally due within one month of receipt of invoices which are presented on a monthly cycle basis.

Other receivables consist primarily of amounts due from Santee Cooper related to the construction and operation of jointly owned nuclear generating facilities at Summer Station.

Inventories

Materials and supplies include the average cost of transmission, distribution, and generating plant materials. Materials are charged to inventory when purchased and then expensed or capitalized to plant, as appropriate, at weighted average cost when used. Fuel inventory includes the average cost of coal, natural gas, fuel oil and emission allowances. Fuel is charged to inventory when purchased and is expensed, at weighted average cost, as used and recovered through fuel cost recovery rates approved by the SCPSC.

Income Taxes

Consolidated SCE&G is included in the consolidated federal income tax returns of SCANA. Under a joint consolidated income tax allocation agreement, each SCANA subsidiary’s current and deferred tax expense is computed on a stand-alone basis. Deferred tax assets and liabilities are recorded for the tax effects of all significant temporary differences between the book basis and tax basis of assets and liabilities at currently enacted tax rates. Deferred tax assets and liabilities are adjusted for changes in such tax rates through charges or credits to regulatory assets or liabilities if they are expected to be recovered from, or passed through to, customers; otherwise, they are charged or credited to income tax expense. Also under provisions of the income tax allocation agreement, certain tax benefits of the parent holding company are distributed in cash to tax paying affiliates, including Consolidated SCE&G, in the form of capital contributions.

Regulatory Assets and Regulatory Liabilities

Consolidated SCE&G records costs that have been or are expected to be allowed in the ratemaking process in a period different from the period in which the costs would be charged to expense or record revenue in a period different from the period in which the revenue would be recorded by a nonregulated enterprise. These expenses deferred for future recovery from customers or obligations to be refunded to customers are primarily classified in the balance sheet as regulatory assets and regulatory liabilities (see Note 2) and are amortized consistent with the treatment of the related costs or revenues in the

ratemaking process. Deferred amounts expected to be recovered or repaid within 12 months are classified in the balance sheet as receivables or accounts payable, respectively.

Debt Issuance Premiums, Discounts and Other Costs

ratemaking process. Deferred amounts expected to be recovered or repaid within 12 months are classified in the balance sheet as receivables or accounts payable, respectively.

Debt Issuance Premiums, Discounts and Other Costs

Consolidated SCE&G presents long-term debt premiums, discounts and debt issuance costs within long-term debt and amortizes them as components of interest charges over the terms of the respective debt issues. Gains or losses on reacquired debt that is refinanced are recorded in other deferred debits or credits and are amortized over the term of the replacement debt, also as interest charges.

Environmental

SCE&G maintains an environmental assessment program to identify and evaluate current and former operations sites that could require environmental clean-up. As site assessments are initiated, estimates are made of the amount of expenditures, if any, deemed necessary to investigate and remediate each site. Environmental remediation liabilities are accrued when the criteria for loss contingencies are met. These estimates are refined as additional information becomes available; therefore, actual expenditures could differ significantly from the original estimates. Probable and estimable costs are accrued related to environmental sites on an undiscounted basis. Amounts estimated and accrued to date for site assessments and clean-up relate solely to regulated operations. Amounts expected to be recovered through rates are recorded in regulatory assets and, if applicable, amortized over approved amortization periods. Other environmental costs are expensed as incurred.

Income Statement Presentation

Consolidated SCE&G presents the revenues and expenses of its regulated activities (including those activities of segments described in Note 12) within operating income, and it presents all other activities within other income (expense).

Revenue Recognition

Consolidated SCE&G records revenues during the accounting period in which it provides services to customers and includes estimated amounts for electricity and natural gas delivered but not billed. Unbilled revenues totaled $101.5 million at December 31, 2015 and $115.8 million at December 31, 2014.

Fuel costs, emission allowances and certain environmental reagent costs for electric generation are collected through the fuel cost component in retail electric rates. The SCPSC establishes this component during fuel cost hearings. Any difference between actual fuel costs and amounts contained in the fuel cost component is adjusted through revenue and is deferred and included when determining the fuel cost component during subsequent hearings.

Customers subject to the PGA are billed based on a cost of gas factor calculated in accordance with a gas cost recovery procedure approved by the SCPSC and subject to adjustment monthly. Any difference between actual gas costs and amounts contained in rates is adjusted through revenue and is deferred and included when making the next adjustment to the cost of gas factor.

SCE&G’s gas rate schedules for residential, small commercial and small industrial customers include a WNA which minimizes fluctuations in gas revenues due to abnormal weather conditions. An eWNA for SCE&G's electric customers was discontinued effective with the first billing cycle of 2014 as approved by the SCPSC.

Taxes that are billed to and collected from customers are recorded as liabilities until they are remitted to the respective taxing authority. Such taxes are not included in revenues or expenses in the statements of income.

New Accounting Matters

In May 2014, the FASB issued accounting guidance for revenue arising from contracts with customers that supersedes most current revenue recognition guidance, including industry-specific guidance. This revenue recognition model provides a five-step analysis in determining when and how revenue is recognized, and will require revenue recognition to depict the transfer of promised goods or services to customers in an amount that reflects the consideration a company expects to receive in exchange for those goods or services. Consolidated SCE&G is required to adopt this guidance in the first quarter of 2018 and early adoption is permitted in the first quarter of 2017. Adoption using a retrospective method is required, with options to elect certain practical expedients or to recognize a cumulative effect in the year of initial adoption. Consolidated SCE&G has not

determined when it will adopt this guidance or what elections it will make. Consolidated SCE&G has not determined the impact this guidance will have on its results of operations, cash flows or financial position.

In April 2015, the FASB issued accounting guidance related to fees paid by a customer in a cloud computing arrangement. Among other determined when it will adopt this guidance or what elections it will make. Consolidated SCE&G has not determined the impact this guidance will have on its results of operations, cash flows or financial position.

In April 2015, the FASB issued accounting guidance related to fees paid by a customer in a cloud computing arrangement. Among other things, the guidance clarifies how to account for a software license element included in a cloud computing arrangement, and makes explicit that a cloud computing arrangement not containing a software license element should be accounted for as a service contract. Consolidated SCE&G has determined that this guidance, when adopted in the first quarter of 2016, will not significantly impact Consolidated SCE&G’s results of operations, cash flows or financial position.

In July 2015, the FASB issued accounting guidance intended to simplify the subsequent measurement of inventory cost by requiring most inventory to be measured at the lower of cost and net realizable value. Consolidated SCE&G expects to adopt this guidance when required in the first quarter of 2017. Consolidated SCE&G is evaluating this guidance and has not determined what impact it will have on its results of operations, cash flows or financial position.

In January 2016, the FASB issued accounting guidance intended to clarify the classification and measurement of financial instruments and financial liabilities, among other things. Consolidated SCE&G expects to adopt this guidance when required in the first quarter of 2018. Consolidated SCE&G is evaluating this guidance and has not determined what impact it will have on its results of operations, cash flows or financial position.

In February 2016, the FASB issued accounting guidance related to the recognition, measurement and presentation of leases. The guidance applies a right-of-use model and, for lessees, requires all leases with a duration over twelve months to be recorded on the balance sheet, with the rights of use treated as assets and the payment obligations treated as liabilities. Further, and without consideration of any regulatory accounting requirements which may apply, depending primarily of the nature of the assets and the relative consumption of them, lease costs will be recognized either through the separate amortization of the right-of-use asset and the recognition of the interest cost related to the payment obligation, or through the recording of a combined straight-line rental expense. For lessors, the guidance calls for the recognition of income either through the derecognition of assets and subsequent recording of interest income on lease amounts receivable, or through the recognition of rental income on a straight line basis, also depending on the nature of the assets and relative consumption. The guidance will be effective for year beginning in 2019. Consolidated SCE&G has not determined what impact this guidance will have on its results of operations, cash flows or financial position.

2. RATE AND OTHER REGULATORY MATTERS

Electric - Cost of Fuel

SCE&G's retail electric rates include a cost of fuel component approved by the SCPSC which may be adjusted periodically to reflect changes in the price of fuel purchased by SCE&G.

Pursuant to a November 2013 SCPSC accounting order, SCE&G's electric revenue for 2013 was reduced for adjustments to the fuel cost component and related under-collected fuel balance of $41.6 million. Such adjustments are fully offset by the recognition within other income, also pursuant to that accounting order, of gains realized upon the settlement of certain interest rate derivatives which had been entered into in anticipation of the issuance of long-term debt, which gains had been deferred as a regulatory liability. See also Note 6.

Pursuant to an April 2014 SCPSC order, SCE&G increased its base fuel cost component by approximately $10.3 million for the 12-month period beginning with the first billing cycle of May 2014. The base fuel cost increase was offset by a reduction in SCE&G's rate rider related to pension costs approved by the SCPSC in March 2014. In addition, pursuant to the April 2014 order, electric revenue for 2014 was reduced by approximately $46 million for adjustments to the fuel cost component and related under-collected fuel balance. Such adjustments are fully offset by the recognition within other income of gains realized from the late 2013 settlement of certain interest rate derivatives which had been entered into in anticipation of the issuance of long-term debt, which gains had been deferred as a regulatory liability. The order also provided for the accrual of certain debt-related carrying costs on its under-collected balance of base fuel costs from May 1, 2014 through April 30, 2015.

The cost of fuel includes amounts paid by SCE&G pursuant to the Nuclear Waste Act for the disposal of spent nuclear fuel. As a result of a November 2013 decision by the Court of Appeals, the DOE set the Nuclear Waste Act fee to zero effective May 16, 2014. The impact of changes to the Nuclear Waste Act fee is considered during annual fuel rate proceedings.

By order dated April 30, 2015, the SCPSC approved a settlement agreement among SCE&G and certain other parties in which SCE&G agreed to decrease the total fuel cost component of retail electric rates. Under this order, SCE&G is to recover an amount equal to its under-collected balance of base fuel and variable environmental costs as of April 30, 2015, over the subsequent 12-month period beginning with the first billing cycle of May 2015.

By order dated July 15, 2015, the SCPSC approved a settlement agreement among SCE&G and certain other parties concerning SCE&G's

By order dated April 30, 2015, the SCPSC approved a settlement agreement among SCE&G and certain other parties in which SCE&G agreed to decrease the total fuel cost component of retail electric rates. Under this order, SCE&G is to recover an amount equal to its under-collected balance of base fuel and variable environmental costs as of April 30, 2015, over the subsequent 12-month period beginning with the first billing cycle of May 2015.

By order dated July 15, 2015, the SCPSC approved a settlement agreement among SCE&G and certain other parties concerning SCE&G's petition for approval to participate in a DER program and to recover DER program costs as a separate component of SCE&G's overall fuel factor. Under this order, SCE&G will, among other things, implement programs to encourage the development of renewable energy facilities with a total nameplate capacity of at least approximately 84.5 MW by the end of 2020, of which half is to be customer-scale solar capacity and half is to be utility-scale solar capacity. SCE&G is to make a good faith effort to have at least 30 MW of utility-scale solar capacity in service by the end of 2016.

By order dated September 16, 2015, the SCPSC approved SCE&G's request to adopt lower depreciation rates for electric and common plant effective January 1, 2015. These rates were based on the results of a depreciation study conducted by SCE&G using utility plant balances as of December 31, 2014. In connection with the adoption of the revised depreciation rates, SCE&G recorded lower depreciation expense of approximately $29 million in 2015, and pursuant to the SCPSC order, SCE&G reduced its electric operating revenues by approximately $14.5 million with an offset to under-collected fuel included within Receivables in the balance sheet. Accordingly, SCE&G's net income for 2015 increased approximately $9.8 million as a result of this change in estimate.

In October 2015, the SCPSC initiated its 2016 annual review of base rates for fuel costs. A public hearing for this annual review is scheduled for April 7, 2016.

Electric - Base Rates

Prior to 2014, certain of SCE&G's electric rates included an adjustment for eWNA. The eWNA was designed to mitigate the effects of abnormal weather on residential and commercial customers' bills. On November 26, 2013, SCE&G, ORS and certain other parties filed a joint petition with the SCPSC requesting, among other things, that the SCPSC discontinue the eWNA effective with bills rendered on or after the first billing cycle of January 2014. On December 20, 2013, the SCPSC granted the relief requested in the joint petition. In connection with the termination of the eWNA effective December 31, 2013, and pursuant to an SCPSC order, electric revenues were reduced to reverse the prior accrual of an under-collected balance of $8.5 million. This revenue reduction was fully offset by the recognition within other income of $8.5 million of gains realized upon the settlement of certain interest rate derivatives, which gains had been deferred as a regulatory liability.

Pursuant to an SCPSC order, SCE&G removes from rate base deferred income tax assets arising from capital expenditures related to the New Units and accrues carrying costs on those amounts during periods in which they are not included in rate base. Such carrying costs are determined at SCE&G’s weighted average long-term debt borrowing rate and are recorded as a regulatory asset and other income. Carrying costs totaled $9.5 million and $5.8 million during 2015 and 2014, respectively. SCE&G anticipates that when the New Units are placed in service and accelerated tax depreciation is recognized on them, these deferred income tax assets will decline. When these assets are fully offset by related deferred income tax liabilities, the carrying cost accruals will cease, and the regulatory asset will begin to be amortized.

The SCPSC has approved a suite of DSM Programs for development and implementation. SCE&G offers to its retail electric customers several distinct programs designed to assist customers in reducing their demand for electricity and improving their energy efficiency. SCE&G submits annual filings to the SCPSC related to these programs which include actual program costs, net lost revenues (both forecasted and actual), customer incentives, and net program benefits, among other things. As actual DSM Program costs are incurred, they are deferred as regulatory assets and recovered through a rate rider approved by the SCPSC. The rate rider also provides for recovery of net lost revenues and for a shared savings incentive. The SCPSC approved the following rate riders pursuant to the annual DSM Programs filings, which went into effect as indicated below:

Year	Effective	Amount
2015	First billing cycle of May	$32.0 million
2014	First billing cycle of May	$15.4 million
2013	First billing cycle of May	$16.9 million

In April 2014, the SCPSC issued an order approving, among other things, SCE&G’s request to utilize approximately $17.8 million of the gains from the late 2013 settlement of certain interest rate derivative instruments, previously deferred as regulatory liabilities, to offset a portion of SCE&G’s DSM Programs rate rider. This order also allowed SCE&G to apply $5.0 million of its storm damage reserve and $5.0 million of the gains from the settlement of certain interest rate derivative instruments to offset previously deferred amounts.

In April 2014, the SCPSC issued an order approving, among other things, SCE&G's request to utilize approximately $17.8 million of the gains from the late 2013 settlement of certain interest rate derivative instruments, previously deferred as regulatory liabilities, to offset a portion of SCE&G's DSM Programs rate rider. This order also allowed SCE&G to apply $5.0 million of its storm damage reserve and $5.0 million of the gains from the settlement of certain interest rate derivative instruments to offset previously deferred amounts.

In January 2016, SCE&G submitted its annual DSM Programs filing to the SCPSC. If approved, the filing would allow recovery of $37.6 million of costs and net lost revenues associated with the DSM Programs, along with an incentive to invest in such programs.

Electric - BLRA

Under the BLRA, SCE&G may file revised rates with the SCPSC each year to incorporate the financing cost of any incremental construction work in progress incurred for new nuclear generation. Through 2015, requested rate adjustments have been based on SCE&G's updated cost of debt and capital structure and on an allowed return on common equity of 11.0%. The SCPSC has approved recovery of the following amounts under the BLRA effective for bills rendered on and after October 30 in the following years:

Year	Increase	Amount
2015	2.6%	$64.5 million
2014	2.8%	$66.2 million
2013	2.9%	$67.2 million

In September 2015, the SCPSC approved a revision to the allowed return on equity for new nuclear construction from 11.0% to 10.5%. This revised return on equity will be applied prospectively for the purpose of calculating revised rates sought by SCE&G under the BLRA on and after January 1, 2016, until such time as the New Units are completed. See Note 10.

Gas

The RSA is designed to reduce the volatility of costs charged to customers by allowing for more timely recovery of the costs that regulated utilities incur related to natural gas infrastructure. The SCPSC has approved the following rate changes pursuant to annual RSA filings effective with the first billing cycle of November in the following years:

Year	Action	Amount
2015	No change	—
2014	0.6% Decrease	$ 2.6 million
2013	No change	—

SCE&G's natural gas tariffs include a PGA that provides for the recovery of actual gas costs incurred, including transportation costs. SCE&G's gas rates are calculated using a methodology which may adjust the cost of gas monthly based on a 12-month rolling average, and its gas purchasing policies and practices are reviewed annually by the SCPSC. The annual reviews conducted for each of the 12-month periods ended July 31, 2015 and 2014 resulted in the SCPSC issuing an order finding that SCE&G's gas purchasing policies and practices during each of the review periods were reasonable and prudent.

Regulatory Assets and Regulatory Liabilities

Consolidated SCE&G has significant cost-based, rate-regulated operations and recognizes in its financial statements certain revenues and expenses in different time periods than do enterprises that are not rate-regulated. As a result, Consolidated SCE&G has recorded regulatory assets and regulatory liabilities, which are summarized in the following tables. Other than unrecovered plant, substantially all regulatory assets are either explicitly excluded from rate base or are effectively excluded from rate base due to their being offset by related liabilities.

	December 31,	
Millions of dollars	**2015**	**2014**
Regulatory Assets:		
Accumulated deferred income taxes	$ 291	$ 278
AROs and related funding	384	347
Deferred employee benefit plan costs	295	310

Millions of dollars	December 31, 2015	December 31, 2014
Regulatory Assets:		
Accumulated deferred income taxes	$ 291	$ 278
AROs and related funding	384	347
Deferred employee benefit plan costs	295	310
Deferred losses on interest rate derivatives	535	453
Unrecovered plant	127	137
Environmental remediation costs	35	36
DSM Programs	61	56
Other	129	128
Total Regulatory Assets	$ 1,857	$ 1,745
Regulatory Liabilities:		
Asset removal costs	519	505
Deferred gains on interest rate derivatives	96	82
Other	20	23
Total Regulatory Liabilities	$ 635	$ 610

Accumulated deferred income tax liabilities that arose from utility operations that have not been included in customer rates are recorded as a regulatory asset. Substantially all of these regulatory assets relate to AFC and are expected to be recovered over the remaining lives of the related property which may range up to approximately 85 years.

ARO and related funding represents the regulatory asset associated with the legal obligation to decommission and dismantle Summer Station and conditional AROs related to generation, transmission and distribution properties, including gas pipelines. These regulatory assets are expected to be recovered over the related property lives and periods of decommissioning which may range up to approximately 110 years.

Employee benefit plan costs of the regulated utilities have historically been recovered as they have been recorded under GAAP. Deferred employee benefit plan costs represent pension and other postretirement benefit costs which were accrued as liabilities and treated as regulatory assets pursuant to FERC guidance, and costs deferred pursuant to specific SCPSC regulatory orders. Accordingly, in 2013 SCE&G began recovering through utility rates approximately $63 million of deferred pension costs for electric operations over approximately 30 years and approximately $14 million of deferred pension costs for gas operations over approximately 14 years. The remainder of the deferred benefit costs are expected to be recovered through utility rates, primarily over average service periods of participating employees, or up to approximately 12 years.

Deferred losses or gains on interest rate derivatives represent (i) the effective portions of changes in fair value and payments made or received upon settlement of certain interest rate derivatives designated as cash flow hedges and (ii) the changes in fair value and payments made or received upon settlement of certain other interest rate derivatives not so designated. The amounts recorded with respect to (i) are expected to be amortized to interest expense over the lives of the underlying debt through 2043. The amounts recorded with respect to (ii) are expected to be similarly amortized to interest expense through 2065 except when, in the case of deferred gains, such amounts are applied otherwise at the direction of the SCPSC.

Unrecovered plant represents the carrying value of coal-fired generating units, including related materials and supplies inventory, retired from service prior to being fully depreciated. Pursuant to SCPSC approval, SCE&G will amortize these amounts through cost of service rates over the units' previous estimated remaining useful lives through approximately 2025. Unamortized amounts are included in rate base and are earning a current return.

Environmental remediation costs represent costs associated with the assessment and clean-up of sites currently or formerly owned by SCE&G and are expected to be recoverable over periods of up to approximately 24 years.

DSM Programs represent deferred costs associated with such programs. As a result of an April 2015 SCPSC order, deferred costs are currently being recovered over approximately five years through an approved rate rider.

Various other regulatory assets are expected to be recovered in rates over periods of up to approximately 30 years.

Asset removal costs represent estimated net collections through depreciation rates of amounts to be incurred for the removal of assets in the future.

The SCPSC or the FERC has reviewed and approved through specific orders most of the items shown as regulatory assets. Other regulatory assets include, but are not limited to, certain costs which have not been specifically approved for recovery by the SCPSC or by the FERC. In recording such costs as regulatory assets, management believes the costs will be allowable under existing rate-making concepts that are embodied in rate orders received by SCE&G. The costs are currently not being recovered, but are expected to be recovered through rates in future periods. In the future, as a result of deregulation or other changes in the regulatory environment or changes in accounting requirements, Consolidated SCE&G could be required to write off its regulatory assets and liabilities. Such an event could have a material effect on Consolidated SCE&G's results of operations, liquidity or financial position in the period the write-off would be recorded.

3. EQUITY

Authorized shares of SCE&G common stock were 50 million as of December 31, 2015 and 2014. Authorized shares of SCE&G preferred stock were 20 million, of which 1,000 shares, no par value, were held by SCANA as of December 31, 2015 and 2014.

SCE&G's articles of incorporation do not limit the dividends that may be paid on its common stock. However, SCE&G's bond indenture contains provisions that, under certain circumstances, which SCE&G considers to be remote, could limit the payment of cash dividends on its common stock.

The Federal Power Act requires the appropriation of a portion of certain earnings from hydroelectric projects. At December 31, 2015 and 2014, retained earnings of approximately $72.4 million and $67.7 million, respectively, were restricted by this requirement as to payment of cash dividends on common stock.

4. LONG-TERM AND SHORT-TERM DEBT

Total long-term debt, net reflects the retrospective adoption of accounting guidance for unamortized debt issuance costs in the fourth quarter of 2015 (see Note 1). Long-term debt by type with related weighted average effective interest rates and maturities at December 31 is as follows:

		2015		2014	
Dollars in millions	**Maturity**	**Balance**	**Rate**	**Balance**	**Rate**
First Mortgage Bonds (secured)	2018 - 2065	$ 4,340	5.78%	$ 3,840	5.56%
GENCO Notes (secured)	2016 - 2024	220	5.92%	227	5.90%
Industrial and Pollution Control Bonds (a)	2028 - 2038	122	3.51%	122	3.51%
Nuclear Fuel Financing	2016	100	0.78%	100	0.78%
Other	2016 - 2027	17	2.63%	14	2.63%
Total debt		4,799		4,303	
Current maturities of long-term debt		(110)		(10)	
Unamortized premium, net		2		6	
Unamortized debt issuance costs		(32)		(29)	
Total long-term debt, net		$ 4,659		$ 4,270	

(a) Includes variable rate debt of $67.8 million at December 31, 2015 (rate of 0.03%) and 2014 (rate of 0.04%), which are hedged by fixed swaps.

In May 2015, SCE&G issued $500 million of 5.1% first mortgage bonds due June 1, 2065. Proceeds from this sale were used to repay short-term debt primarily incurred as a result of SCE&G's construction program, to finance capital expenditures, and for general corporate purposes.

In May 2014, SCE&G issued $300 million of 4.5% first mortgage bonds due June 1, 2064. Proceeds from this sale were used to repay short-term debt primarily incurred as a result of SCE&G's construction program, to finance capital expenditures, and for general corporate purposes.

Long-term debt maturities will be $110 million in 2016, $10 million in 2017, $720 million in 2018, $9 million in 2019 and $8 million in 2020.

Substantially all electric utility plant is pledged as collateral in connection with long-term debt.

SCE&G is subject to a bond indenture dated April 1, 1993 (Mortgage) covering substantially all of its electric properties under which all of its first mortgage bonds (Bonds) have been issued. Bonds may be issued under the Mortgage in an aggregate principal amount not exceeding the sum of (1) 70% of Unfunded Net Property Additions (as therein defined), (2) the aggregate principal amount of retired Bonds and (3) cash deposited with the trustee. Bonds, other than certain Bonds issued on the basis of retired Bonds, may be issued under the Mortgage only if Adjusted Net Earnings (as therein defined) for 12 consecutive months out of the 18 months immediately preceding the month of issuance are at least twice (2.0) the annual interest requirements on all outstanding Bonds and Bonds to be outstanding (Bond Ratio). For the year ended December 31, 2015, the Bond Ratio was 5.17.

Lines of Credit and Short-Term Borrowings

At December 31, 2015 and 2014, SCE&G (including Fuel Company) had available the following committed LOC and had outstanding the following LOC-related obligations and commercial paper borrowings:

Millions of dollars	**2015**	**2014**
Lines of credit:		
Total committed long-term	$ 1,400	$ 1,400
Outstanding commercial paper (270 or fewer days)	$ 420	$ 709
Weighted average interest rate	0.74%	0.52%
Letters of credit supported by an LOC	$ 0.3	$ 0.3
Available	$ 980	$ 691

SCE&G and Fuel Company are parties to five-year credit agreements in the amount of $1.2 billion (of which $500 million relates to Fuel Company). In addition, SCE&G is party to a three-year credit agreement in the amount of $200 million. In December 2015, the term of the five-year agreements was amended and extended by one year, such that they expire in December 2020. The three-year agreement expires in December 2018. These credit agreements are used for general corporate purposes, including liquidity support for each company's commercial paper program and working capital needs and, in the case of Fuel Company, to finance or refinance the purchase of nuclear fuel, certain fossil fuels, and emission and other environmental allowances. These committed long-term facilities are revolving lines of credit under credit agreements with a syndicate of banks. Wells Fargo Bank, National Association, Bank of America, N.A. and Morgan Stanley Bank, N.A. each provide 9.5% of the aggregate credit facilities, JPMorgan Chase Bank, N.A., Mizuho Corporate Bank, Ltd., TD Bank N.A., Credit Suisse AG, Cayman Islands Branch, UBS Loan Finance LLC, MUFG Union Bank, N.A., and Branch Banking and Trust Company each provide 7.9%, and Royal Bank of Canada and U.S. Bank National Association each provide 5.5%. Two other banks provide the remaining support. Consolidated SCE&G pays fees to the banks as compensation for maintaining the committed lines of credit. Such fees were not material in any period presented.

Consolidated SCE&G is obligated with respect to an aggregate of $67.8 million of industrial revenue bonds which are secured by letters of credit issued by TD Bank N.A. These letters of credit expire, subject to renewal, in the fourth quarter of 2019.

Consolidated SCE&G participates in a utility money pool with SCANA and certain other subsidiaries of SCANA. Money pool borrowings and investments bear interest at short-term market rates. Consolidated SCE&G's interest income and expense from money pool transactions were not significant for any period presented. At December 31, 2015 Consolidated SCE&G had outstanding money pool borrowings due to an affiliate of $33 million and money pool investments due from an affiliate of $9 million. At December 31, 2014 Consolidated SCE&G had outstanding money pool borrowings due to an affiliate of $83 million and money pool investments due from an affiliate of $80 million. On the consolidated balance sheets, amounts due from an affiliate are included within Receivables-affiliated companies, and amounts due to an affiliate are included within Affiliated payables.

5. INCOME TAXES

Components of income tax expense are as follows:

Millions of dollars	**2015**	**2014**	**2013**
Current taxes:			
Federal	$ 208	$ 39	$ 146

5. INCOME TAXES

Components of income tax expense are as follows:

Millions of dollars	2015	2014	2013
Current taxes:			
Federal	$ 208	$ 39	$ 146
State	32	(6)	13
Total current taxes	240	33	159
Deferred tax (benefit) expense, net:			
Federal	(3)	157	25
State	(3)	32	9
Total deferred taxes	(6)	189	34
Investment tax credits:			
Amortization of amounts deferred—state	(1)	(1)	(1)
Amortization of amounts deferred—federal	(2)	(3)	(3)
Total investment tax credits	(3)	(4)	(4)
Total income tax expense	$ 231	$ 218	$ 189

The difference between actual income tax expense and the amount calculated from the application of the statutory 35% federal income tax rate to pre-tax income is reconciled as follows:

Millions of dollars	2015	2014	2013
Net income	$ 466	$ 446	$ 380
Income tax expense	231	218	189
Noncontrolling interest	14	12	11
Total pre-tax income	$ 711	$ 676	$ 580
Income taxes on above at statutory federal income tax rate	$ 249	$ 237	$ 203
Increases (decreases) attributed to:			
State income taxes (less federal income tax effect)	24	21	18
State investment tax credits (less federal income tax effect)	(6)	(5)	(5)
Allowance for equity funds used during construction	(9)	(10)	(9)
Amortization of federal investment tax credits	(2)	(3)	(3)
Section 41 tax credits	1	(3)	—
Section 45 tax credits	(9)	(9)	(5)
Domestic production activities deduction	(18)	(7)	(11)
Other differences, net	1	(3)	1
Total income tax expense	$ 231	$ 218	$ 189

The tax effects of significant temporary differences comprising Consolidated SCE&G’s net deferred tax liability are as follows:

Millions of dollars	2015	2014
Deferred tax assets:		
Nondeductible accruals	$ 52	$ 47
Asset retirement obligation, including nuclear decommissioning	187	205
Unamortized investment tax credits	16	17

The tax effects of significant temporary differences comprising Consolidated SCE&G’s net deferred tax liability are as follows:

Millions of dollars	**2015**	**2014**
Deferred tax assets:		
Nondeductible accruals	$ 52	$ 47
Asset retirement obligation, including nuclear decommissioning	187	205
Unamortized investment tax credits	16	17
Deferred fuel costs	7	—
Financial instruments	2	—
Other	2	6
Total deferred tax assets	266	275
Deferred tax liabilities:		
Property, plant and equipment	$ 1,644	$ 1,623
Regulatory asset, asset retirement obligation	127	115
Deferred employee benefit plan costs	85	91
Deferred fuel costs	—	27
Regulatory asset, unrecovered plant	49	53
Regulatory asset, net loss on interest rate derivative contracts settlement	—	21
Demand side management costs	23	21
Prepayments	29	25
Other	41	23
Total deferred tax liabilities	1,998	1,999
Net deferred tax liability	$ 1,732	$ 1,724

Consolidated SCE&G is included in the consolidated federal income tax return of SCANA and files various applicable state and local income tax returns. The IRS has completed examinations of SCANA’s federal returns through 2004, and SCANA’s federal returns through 2007 are closed for additional assessment. The IRS is currently examining SCANA's open federal returns through 2014 as a result of claims discussed below in Changes to Unrecognized Tax Benefits. With few exceptions, Consolidated SCE&G is no longer subject to state and local income tax examinations by tax authorities for years before 2010.

Changes to Unrecognized Tax Benefits

Millions of dollars	**2015**	**2014**	**2013**
Unrecognized tax benefits, January 1	$ 16	$ 3	—
Gross increases-uncertain tax positions in prior period	33	—	—
Gross decreases-uncertain tax positions in prior period	(2)	—	—
Gross increases-current period uncertain tax positions	2	13	$ 3
Unrecognized tax benefits, December 31	$ 49	$ 16	$ 3

During 2013 and 2014, Consolidated SCE&G amended certain of its tax returns to claim certain tax-defined research and development deductions and credits and its related impact on domestic production activities. Consolidated SCE&G also made similar claims in filing its 2013 and 2014 returns in 2014 and 2015, respectively. In connection with these federal and state filings, Consolidated SCE&G recorded an unrecognized tax benefit of $49 million. During 2015, as the IRS' examination progressed, without resolution, Consolidated SCE&G evaluated and recorded adjustments to its unrecognized tax benefits; however, none of these changes materially affected Consolidated SCE&G's effective tax rate. If recognized, $17 million of the tax benefits would affect Consolidated SCE&G's effective tax rate. It is reasonably possible that these tax benefits will increase by an additional $7 million within the next 12 months. It is also reasonably possible that these tax benefits may decrease by $8 million within the next 12 months. No other material changes in the status of Consolidated SCE&G's tax positions have occurred through December 31, 2015.

Consolidated SCE&G recognizes interest accrued related to unrecognized tax benefits within interest expense or interest income and recognizes tax penalties within other expenses. In connection with the resolution of the uncertainty and recognition of the tax benefit, Consolidated SCE&G has not recorded a material amount of interest income, interest expense, or penalties associated with any uncertain tax position.

6. DERIVATIVE FINANCIAL INSTRUMENTS

Consolidated SCE&G recognizes all derivative instruments as either assets or liabilities in its statements of financial position and measures those instruments at fair value. Consolidated SCE&G recognizes changes in the fair value of derivative instruments either in earnings or within regulatory assets or regulatory liabilities, depending upon the intended use of the derivative and the resulting designation.

Policies and procedures and risk limits are established to control the level of market, credit, liquidity and operational and administrative risks assumed by Consolidated SCE&G. SCANA's Board of Directors has delegated to a Risk Management Committee the authority to set risk limits, establish policies and procedures for risk management and measurement, and oversee and review the risk management process and infrastructure for SCANA and each of its subsidiaries, including Consolidated SCE&G. The Risk Management Committee, which is comprised of certain officers, including Consolidated SCE&G's Risk Management Officer and senior officers, apprises the Audit Committee of the Board of Directors with regard to the management of risk and brings to their attention significant areas of concern. Written policies define the physical and financial transactions that are approved, as well as the authorization requirements and limits for transactions.

Interest Rate Swaps

Consolidated SCE&G synthetically converts variable rate debt to fixed rate debt using swaps that are designated as cash flow hedges. Periodic payments to or receipts from swap counterparties related to these derivatives are recorded within interest expense.

In anticipation of the issuance of debt, Consolidated SCE&G may use treasury rate lock or forward starting swap agreements. Pursuant to regulatory orders, interest derivatives entered into by SCE&G after October 2013 are not designated as cash flow hedges, and fair value changes and settlement amounts are recorded as regulatory assets and liabilities. Settlement losses on swaps will be amortized over the lives of subsequent debt issuances and gains may be applied to under-collected fuel, may be amortized to interest expense or may be applied as otherwise directed by the SCPSC. As discussed in Note 2, in 2013 the SCPSC directed SCE&G to recognize $41.6 million and $8.5 million of realized gains (which had been deferred in regulatory liabilities) within other income in 2013, fully offsetting revenue reductions related to under-collected fuel balances and under-collected amounts arising under the eWNA program which was terminated at the end of 2013. As also discussed in Note 2, pursuant to regulatory orders in 2014, the SCPSC directed SCE&G to apply $46 million of these deferred gains to reduce under-collected fuel to utilize approximately $17.8 million of these gains to offset a portion of the net lost revenues component of SCE&G's DSM Program rider, and to apply $5.0 million of the gains to the remaining balance of deferred net lost revenues as of April 30, 2014, which had been deferred within regulatory assets.

Cash payments made or received upon settlement of these financial instruments are classified as investing activities for cash flow statement purposes.

Quantitative Disclosures Related to Derivatives

Consolidated SCE&G was a party to interest rate swaps designated as cash flow hedges with aggregate notional amounts of $36.4 million and $36.4 million at December 31, 2015 and 2014, respectively. Consolidated SCE&G was party to interest rate swaps not designated as cash flow hedges with an aggregate notional amount of $1.235 billion and $1.085 billion at December 31, 2015 and 2014, respectively.

The fair value of derivatives in the consolidated balance sheets is as follows:

Fair Values of Derivative Instruments

Millions of dollars	**Balance Sheet Location**	**Asset**	**Liability**
As of December 31, 2015			
Designated as hedging instruments			
Interest rate contracts	Derivative financial instruments		$ 1
	Other deferred credits and other liabilities		9
Total			$ 10
Not designated as hedging instruments			
Interest rate contracts	Other current assets	$ 10	
	Other deferred debits and other assets	5	

The fair value of derivatives in the consolidated balance sheets is as follows:

Fair Values of Derivative Instruments

Millions of dollars	**Balance Sheet Location**	**Asset**	**Liability**
As of December 31, 2015			
Designated as hedging instruments			
Interest rate contracts	Derivative financial instruments		$ 1
	Other deferred credits and other liabilities		9
Total			$ 10
Not designated as hedging instruments			
Interest rate contracts	Other current assets	$ 10	
	Other deferred debits and other assets	5	
	Derivative financial instruments		$ 33
	Other deferred credits and other liabilities		22
Total		$ 15	$ 55
As of December 31, 2014			
Designated as hedging instruments			
Interest rate contracts	Derivative financial instruments		$ 1
	Other deferred credits and other liabilities		8
Total			$ 9
Not designated as hedging instruments			
Interest rate contracts	Derivative financial instruments		$ 207
	Other deferred credits and other liabilities		17
Total			$ 224

The effect of derivative instruments on the consolidated statements of income is as follows:

Derivatives in Cash Flow Hedging Relationships		**Gain (Loss) Reclassified from Deferred Accounts into Income (Effective Portion)**	
Millions of dollars	**Gain (Loss) Deferred in Regulatory Accounts (Effective Portion)**	**Location**	**Amount**
Year Ended December 31, 2015			
Interest rate contracts	$ (3)	Interest expense	$ (3)
Year Ended December 31, 2014			
Interest rate contracts	$ (9)	Interest expense	$ (3)
Year Ended December 31, 2013			
Interest rate contracts	$ 106	Interest expense	$ (3)

As of December 31, 2015, Consolidated SCE&G expects that during the next twelve months reclassifications from regulatory accounts to earnings arising from cash flow hedges designated as hedging instruments will include approximately $2.2 million as an increase to interest expense assuming financial markets remain at their current levels.

Hedge Ineffectiveness

Other gains (losses) recognized in income representing ineffectiveness on interest rate hedges designated as cash flow hedges were insignificant for all periods presented.

Millions of dollars	Gain or (Loss) Deferred in Regulatory Accounts		Gain Reclassified from Deferred Accounts into Income		
			Location	Amount	
Year Ended December 31, 2015					
Interest rate contracts	$	(69)	Other income	$	5
Year Ended December 31, 2014					
Interest rate contracts	$	(352)	Other income	$	64
Year Ended December 31, 2013					
Interest rate contracts	$	39	Other income	$	50

The gains reclassified to other income offset revenue reductions as previously described herein and in Note 2.

As of December 31, 2015, Consolidated SCE&G expects that during the next twelve months reclassifications from regulatory accounts to earnings arising from interest rate swaps not designated as cash flow hedges will include approximately $0.6 million as an increase to interest expense.

Credit Risk Considerations

Consolidated SCE&G limits credit risk in its derivatives activities by assessing the creditworthiness of potential counterparties before entering into transactions with them and continuing to evaluate their creditworthiness on an ongoing basis. In this regard, Consolidated SCE&G uses credit ratings provided by credit rating agencies and current market-based qualitative and quantitative data, as well as financial statements, to assess the financial health of counterparties on an ongoing basis. Consolidated SCE&G uses standardized master agreements which generally include collateral requirements. These master agreements permit the netting of cash flows associated with a single counterparty. Cash, letters of credit and parental/affiliate guarantees may be obtained as security from counterparties in order to mitigate credit risk. The collateral agreements require a counterparty to post cash or letters of credit in the event an exposure exceeds the established threshold. The threshold represents an unsecured credit limit which may be supported by a parental/affiliate guaranty, as determined in accordance with Consolidated SCE&G's credit policies and due diligence. In addition, collateral agreements allow for the termination and liquidation of all positions in the event of a failure or inability to post collateral.

Certain of Consolidated SCE&G’s derivative instruments contain contingent provisions that require Consolidated SCE&G to provide collateral upon the occurrence of specific events, primarily credit rating downgrades. As of December 31, 2015 and 2014, Consolidated SCE&G had posted $13.4 million and $107.1 million, respectively, of collateral related to derivatives with contingent provisions that were in a net liability position. Collateral related to the positions expected to close in the next 12 months are recorded in Other Current Assets on the consolidated balance sheets. Collateral related to the noncurrent positions is recorded in Other within Deferred Debits and Other Assets on the consolidated balance sheets. If all of the contingent features underlying these instruments had been fully triggered as of December 31, 2015 and 2014, Consolidated SCE&G would have been required to post an additional $43.6 million and $125.9 million, respectively, of collateral to its counterparties. The aggregate fair value of all derivative instruments with contingent provisions that are in a net liability position as of December 31, 2015 and 2014, are $57.0 million and $233.0 million, respectively.

In addition, as of December 31, 2015 and December 31, 2014, Consolidated SCE&G has collected no cash collateral related to interest rate derivatives with contingent provisions that are in a net asset position. If all the contingent features underlying these instruments had been fully triggered as of December 31, 2015 and December 31, 2014, Consolidated SCE&G could request $7.3 million and $- million, respectively, of cash collateral from its counterparties. The aggregate fair value of all derivative instruments with contingent provisions that are in a net asset position as of December 31, 2015 and December 31, 2014 is $7.3 million and $- million, respectively.

Information related to Consolidated SCE&G's offsetting derivative assets and liabilities follows:

Offsetting Derivative Assets

Millions of dollars	Gross Amounts of Recognized Assets	Gross Amounts Offset in the Statement of Financial Position	Net Amounts Presented in the Statement of Financial Position	Gross Amounts Not Offset in the Statement of Financial Position		Net Amount
				Financial Instruments	Cash Collateral Received	
As of December 31, 2015						

Information related to Consolidated SCE&G's offsetting derivative assets and liabilities follows:

Offsetting Derivative Assets

Millions of dollars	Gross Amounts of Recognized Assets	Gross Amounts Offset in the Statement of Financial Position	Net Amounts Presented in the Statement of Financial Position	Gross Amounts Not Offset in the Statement of Financial Position: Financial Instruments	Gross Amounts Not Offset in the Statement of Financial Position: Cash Collateral Received	Net Amount
As of December 31, 2015						
Interest rate	$ 15	—	$ 15	$ (8)	—	$ 7
Balance sheet location	Other current assets		$ 10			
	Other deferred debits and other assets		5			
	Total		$ 15			

As of December 31, 2014 Consolidated SCE&G had no derivative assets.

Offsetting Derivative Liabilities

Millions of dollars	Gross Amounts of Recognized Liabilities	Gross Amounts Offset in the Statement of Financial Position	Net Amounts Presented in the Statement of Financial Position	Gross Amounts Not Offset in the Statement of Financial Position: Financial Instruments	Gross Amounts Not Offset in the Statement of Financial Position: Cash Collateral Posted	Net Amount
As of December 31, 2015						
Interest rate	$ 65	—	$ 65	$ (8)	$ (13)	$ 44
Balance sheet location	Derivative financial instruments		$ 34			
	Other deferred credits and other liabilities		31			
	Total		$ 65			
As of December 31, 2014						
Interest rate	$ 233	—	$ 233	—	$ (107)	$ 126
Balance sheet location	Derivative financial instruments		$ 208			
	Other deferred credits and other liabilities		25			
	Total		$ 233			

7. FAIR VALUE MEASUREMENTS, INCLUDING DERIVATIVES

Consolidated SCE&G’s interest rate swap agreements are valued using discounted cash flow models with independently sourced data. Fair value Level 2 measurements were as follows:

Millions of dollars	**As of December 31, 2015** Level 2	**As of December 31, 2014** Level 2
Assets-Interest rate contracts	$ 15	—
Liabilities-Interest rate contracts	65	$ 233

There were no Level 1 or Level 3 fair value measurements for either period presented and there were no transfers of fair value amounts into or out of Levels 1, 2 or 3 during the periods presented.

Financial instruments for which the carrying amount may not equal estimated fair value at December 31, 2015 and December 31, 2014 were as follows:

Millions of dollars	As of December 31, 2015 Carrying Amount	As of December 31, 2015 Estimated Fair Value	As of December 31, 2014 Carrying Amount	As of December 31, 2014 Estimated Fair Value
Long-term debt	$ 4,769.0	$ 5,129.1	$ 4,279.5	$ 5,041.9

Fair values of long-term debt instruments are based on net present value calculations using independently sourced market data that incorporate a developed discount rate using similarly rated long-term debt, along with benchmark interest rates. As such, the aggregate fair values presented above are considered to be Level 2. Early settlement of long-term debt may not be possible or may not be considered prudent.

Carrying values of short-term borrowings approximate their fair values, which are based on quoted prices from dealers in the commercial paper market. These fair values are considered to be Level 2.

8. EMPLOYEE BENEFIT PLANS AND EQUITY COMPENSATION PLAN

Pension and Other Postretirement Benefit Plans

SCE&G participates in SCANA's noncontributory defined benefit pension plan, which covers regular, full-time employees hired before January 1, 2014. SCANA's policy has been to fund the plan as permitted by applicable federal income tax regulations, as determined by an independent actuary.

SCANA's pension plan provides benefits under a cash balance formula for employees hired before January 1, 2000 who elected that option and for all eligible employees hired subsequently. Under the cash balance formula, benefits accumulate as a result of compensation credits and interest credits. Employees hired before January 1, 2000 who elected to remain under the final average pay formula earn benefits based on years of credited service and the employee's average annual base earnings received during the last three years of employment. Benefits under the cash balance formula and the final average pay formula will continue to accrue through December 31, 2023, after which date no benefits will be accrued except that participants under the cash balance formula will continue to earn interest credits.

In addition to pension benefits, SCE&G participates in SCANA's unfunded postretirement health care and life insurance programs which provide benefits to certain active and retired employees. Retirees hired before January 1, 2011 share in a portion of their medical care cost, while employees hired subsequently are responsible for the full costs of retiree medical benefits elected by them. The costs of postretirement benefits other than pensions are accrued during the years the employees render the services necessary to be eligible for these benefits.

The same benefit formula applies to all SCANA subsidiaries participating in the parent sponsored plans and, with regard to the pension plan, there are no legally separate asset pools. The postretirement benefit plans are accounted for as multiple employer plans. The information presented below reflects Consolidated SCE&G's portion of the obligations, assets, funded status, net periodic benefit costs, and other information reported for the parent sponsored plans as a whole. The tabular data presented reflects the use of various cost assignment methodologies and participation assumptions based on Consolidated SCE&G's past and current employees and its share of plan assets.

Changes in Benefit Obligations

The measurement date used to determine pension and other postretirement benefit obligations is December 31. Data related to the changes in the projected benefit obligation for pension benefits and the accumulated benefit obligation for other postretirement benefits are presented below.

Millions of dollars	Pension Benefits 2015	Pension Benefits 2014	Other Postretirement Benefits 2015	Other Postretirement Benefits 2014
Benefit obligation, January 1	$ 773.7	$ 695.7	$ 204.1	$ 181.7
Service cost	19.3	16.0	4.4	3.6
Interest cost	32.2	34.1	9.4	9.4
Plan participants' contributions	—	—	1.9	1.8
Actuarial (gain) loss	(47.0)	82.7	(15.7)	18.6
Benefits paid	(54.2)	(54.8)	(10.3)	(9.6)
Amounts funded to parent	—	—	(2.1)	(1.4)

Millions of dollars	Pension Benefits 2015	Pension Benefits 2014	Other Postretirement Benefits 2015	Other Postretirement Benefits 2014
Benefit obligation, January 1	$ 773.7	$ 695.7	$ 204.1	$ 181.7
Service cost	19.3	16.0	4.4	3.6
Interest cost	32.2	34.1	9.4	9.4
Plan participants' contributions	—	—	1.9	1.8
Actuarial (gain) loss	(47.0)	82.7	(15.7)	18.6
Benefits paid	(54.2)	(54.8)	(10.3)	(9.6)
Amounts funded to parent	—	—	(2.1)	(1.4)
Benefit obligation, December 31	$ 724.0	$ 773.7	$ 191.7	$ 204.1

SCANA adopted new mortality tables and an improvement scale published by the Society of Actuaries in 2014, resulting in an actuarial loss for pension and other post retirement benefit obligations of approximately $22.1 million and $2.1 million, respectively, in 2014. In 2015, based on an evaluation of the mortality experience of the pension plan, SCANA adopted a custom mortality table for purposes of measuring pension and other postretirement benefit obligations at year-end. This change resulted in an actuarial gain for pension and other postretirement benefit obligations of approximately $18.2 million and $2.0 million, respectively, in 2015.

The accumulated benefit obligation for pension benefits was $702.0 million at the end of 2015 and $747.6 million at the end of 2014. The accumulated pension benefit obligation differs from the projected pension benefit obligation above in that it reflects no assumptions about future compensation levels.

Significant assumptions used to determine the above benefit obligations are as follows:

	Pension Benefits 2015	Pension Benefits 2014	Other Postretirement Benefits 2015	Other Postretirement Benefits 2014
Annual discount rate used to determine benefit obligation	4.68%	4.20%	4.78%	4.30%
Assumed annual rate of future salary increases for projected benefit obligation	3.00%	3.00%	3.00%	3.00%

A 7.0% annual rate of increase in the per capita cost of covered health care benefits was assumed for 2015. The rate was assumed to decrease gradually to 5.0% for 2021 and to remain at that level thereafter.

A one percent increase in the assumed health care cost trend rate would increase the postretirement benefit obligation by $0.6 million at December 31, 2015 and by $0.9 million at December 31, 2014. A one percent decrease in the assumed health care cost trend rate would decrease the postretirement benefit obligation by $0.6 million at December 31, 2015 and by $0.8 million at December 31, 2014.

Funded Status

Millions of Dollars December 31,	Pension Benefits 2015	Pension Benefits 2014	Other Postretirement Benefits 2015	Other Postretirement Benefits 2014
Fair value of plan assets	$ 720.1	$ 783.6	—	—
Benefit obligation	724.0	773.7	$ 191.7	$ 204.1
Funded status	$ (3.9)	$ 9.9	$ (191.7)	$ (204.1)

Amounts recognized on the consolidated balance sheets were as follows:

Millions of Dollars December 31,	Pension Benefits 2015	Pension Benefits 2014	Other Postretirement Benefits 2015	Other Postretirement Benefits 2014
Current liability	—	—	$ (9.8)	$ (8.5)
Noncurrent asset	—	$ 9.9	—	—
Noncurrent liability	$ (3.9)	—	(181.9)	(195.6)

Amounts recognized in accumulated other comprehensive loss were as follows:

Millions of Dollars	**Pension Benefits**		**Other Postretirement Benefits**	
December 31,	**2015**	**2014**	**2015**	**2014**
Net actuarial loss	$ 2.0	$ 1.9	$ 0.7	$ 1.0
Prior service cost	—	0.1	—	—
Total	$ 2.0	$ 2.0	$ 0.7	$ 1.0

Amounts recognized in regulatory assets were as follows:

Millions of Dollars	**Pension Benefits**		**Other Postretirement Benefits**	
December 31,	**2015**	**2014**	**2015**	**2014**
Net actuarial loss	$ 193.7	$ 191.9	$ 20.4	$ 35.9
Prior service cost	5.2	8.3	0.2	0.5
Total	$ 198.9	$ 200.2	$ 20.6	$ 36.4

In connection with the joint ownership of Summer Station, as of December 31, 2015 and 2014, SCE&G recorded within deferred debits $20.3 million and $17.8 million, respectively, attributable to Santee Cooper's portion of shared pension costs. As of December 31, 2015 and 2014, SCE&G also recorded within deferred debits $13.8 million and $15.1 million, respectively, from Santee Cooper, representing its portion of the unfunded postretirement benefit obligation.

Changes in Fair Value of Plan Assets

	Pension Benefits	
Millions of dollars	**2015**	**2014**
Fair value of plan assets, January 1	$ 783.6	$ 792.1
Actual return (loss) on plan assets	(9.3)	46.3
Benefits paid	(54.2)	(54.8)
Fair value of plan assets, December 31	$ 720.1	$ 783.6

Investment Policies and Strategies

The assets of the pension plan are invested in accordance with the objectives of (1) fully funding the obligations of the pension plan, (2) overseeing the plan's investments in an asset-liability framework that considers the funding surplus (or deficit) between assets and liabilities, and overall risk associated with assets as compared to liabilities, and (3) maintaining sufficient liquidity to meet benefit payment obligations on a timely basis. During 2013, in connection with the amendments to the plan, SCANA adopted a dynamic investment strategy for the management of the pension plan assets. The strategy will lead to a reduction in equities and an increase in long duration fixed income allocations over time with the intention of reducing volatility of funded status and pension costs.

The pension plan operates with several risk and control procedures, including ongoing reviews of liabilities, investment objectives, levels of diversification, investment managers and performance expectations. The total portfolio is constructed and maintained to provide prudent diversification with regard to the concentration of holdings in individual issues, corporations, or industries.

Transactions involving certain types of investments are prohibited. These include, except where utilized by a hedge fund manager, any form of private equity; commodities or commodity contracts (except for unleveraged stock or bond index futures and currency futures and options); ownership of real estate in any form other than publicly traded securities; short sales, warrants or margin transactions, or any leveraged investments; and natural resource properties. Investments made for the purpose of engaging in speculative trading are also prohibited.

The pension plan asset allocation at December 31, 2015 and 2014 and the target allocation for 2016 are as follows:

	Percentage of Plan Assets
	Target

The pension plan asset allocation at December 31, 2015 and 2014 and the target allocation for 2016 are as follows:

	Percentage of Plan Assets		
	Target Allocation	December 31,	
Asset Category	**2016**	**2015**	**2014**
Equity Securities	58%	57%	57%
Fixed Income	33%	32%	34%
Hedge Funds	9%	11%	9%

For 2016, the expected long-term rate of return on assets will be 7.50%. In developing the expected long-term rate of return assumptions, management evaluates the pension plan's historical cumulative actual returns over several periods, considers the expected active returns across various asset classes and assumes the target allocation is achieved. Management regularly reviews such allocations and periodically rebalances the portfolio when considered appropriate. Additional rebalancing may occur subject to funded status improvements as part of the dynamic investment strategy described previously.

Fair Value Measurements

Assets held by the pension plan are measured at fair value as described below. Assets are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. At December 31, 2015 and 2014, fair value measurements, and the level within the fair value hierarchy in which the measurements fall, were as follows:

	Fair Value Measurements at Reporting Date Using					
Millions of dollars	**Total**	**Level 2**	**Level 3**	**Total**	**Level 2**	**Level 3**
	December 31, 2015			*December 31, 2014*		
Mutual funds	$ 496	$ 496	—	$ 566	$ 566	—
Short-term investment vehicles	12	12	—	18	18	—
US Treasury securities	20	20	—	6	6	—
Corporate debt securities	72	72	—	78	78	—
Municipals	13	13	—	14	14	—
Limited partnerships	30	30	—	29	29	—
Multi-strategy hedge funds	77	—	$ 77	73	—	$ 73
	$ 720	$ 643	$ 77	$ 784	$ 711	$ 73

At December 31, 2015, assets with fair value measurements classified as Level 1 were insignificant. There were no transfers of fair value amounts into or out of Levels 1, 2 or 3 during 2015 or 2014.

The pension plan values certain mutual funds, where applicable, using unadjusted quoted prices from a national stock exchange, such as NYSE and NASDAQ, where the securities are actively traded. Other mutual funds and limited partnerships are valued using the observable prices of the underlying fund assets based on trade data for identical or similar securities or from a national stock exchange for similar assets or broker quotes. Short-term investment vehicles are funds that invest in short-term fixed income instruments and are valued using observable prices of the underlying fund assets based on trade data for identical or similar securities. Government agency securities are valued using quoted market prices or based on models using observable inputs from market sources such as external prices or spreads or benchmarked thereto. Corporate debt securities and municipals are valued based on recently executed transactions, using quoted market prices, or based on models using observable inputs from market sources such as external prices or spreads or benchmarked thereto. Hedge funds represent investments in a hedge fund of funds partnership that invests directly in multiple hedge fund strategies that are not traded on exchanges and do not trade on a daily basis. The fair value of this multi-strategy hedge fund is estimated based on the net asset value of the underlying hedge fund strategies using consistent valuation guidelines that account for variations that may impact their fair value. The estimated fair value is the price at which redemptions and subscriptions occur.

	Fair Value Measurements Level 3	
Millions of dollars	**2015**	**2014**
Beginning Balance	$ 73	$ 69
Unrealized gains included in changes in net assets	4	4
Purchases, issuances, and settlements	—	—

Ending Balance	$ 77	$ 73

Expected Cash Flows

The total benefits expected to be paid from the pension plan or from Consolidated SCE&G's assets for the other postretirement benefits plan (net of participant contributions), respectively, are as follows:

Expected Benefit Payments

Millions of dollars	**Pension Benefits**	**Other Postretirement Benefits**
2016	$ 65.1	$ 9.8
2017	63.2	10.5
2018	64.7	11.1
2019	65.3	11.7
2020	65.8	12.3
2021 - 2025	338.3	66.1

Pension Plan Contributions

The pension trust is adequately funded under current regulations. No contributions have been required since 1997, and as a result of closing the plan to new entrants and freezing benefit accruals in the future, SCE&G does not anticipate making significant contributions to the pension plan for the foreseeable future.

Net Periodic Benefit Cost

Consolidated SCE&G records net periodic benefit cost utilizing beginning of the year assumptions. Disclosures required for these plans are set forth in the following tables.

Components of Net Periodic Benefit Cost

	Pension Benefits			**Other Postretirement Benefits**		
Millions of dollars	**2015**	**2014**	**2013**	**2015**	**2014**	**2013**
Service cost	$ 19.3	$ 16.0	$ 17.6	$ 4.4	$ 3.6	$ 4.6
Interest cost	32.2	34.1	32.6	9.4	9.4	8.7
Expected return on assets	(52.2)	(56.3)	(51.9)	n/a	n/a	n/a
Prior service cost amortization	3.4	3.5	5.0	0.3	0.3	0.6
Amortization of actuarial losses	11.4	4.0	14.3	1.7	—	2.6
Curtailment	—	—	8.4	—	—	—
Net periodic benefit cost	$ 14.1	$ 1.3	$ 26.0	$ 15.8	$ 13.3	$ 16.5

In connection with regulatory orders, SCE&G recovers current pension expense through a rate rider that may be adjusted annually (for retail electric operations) or through cost of service rates (for gas operations). For retail electric operations, current pension expense is recognized based on amounts collected through its rate rider, and differences between actual pension expense and amounts recognized pursuant to the rider are deferred as a regulatory asset (for under-collections) or regulatory liability (for over-collections) as applicable. In addition, SCE&G amortizes certain previously deferred pension costs. See Note 2.

Other changes in plan assets and benefit obligations recognized in OCI (net of tax) were as follows:

	Pension Benefits			**Other Postretirement Benefits**		
Millions of dollars	**2015**	**2014**	**2013**	**2015**	**2014**	**2013**
Current year actuarial (gain) loss	$ 0.2	$ 0.2	$ (0.8)	$ (0.3)	$ 0.4	$ (0.4)
Amortization of actuarial losses	(0.1)	(0.1)	(0.1)	—	—	(0.1)

Expected Cash Flows

The total benefits expected to be paid from the pension plan or from Consolidated SCE&G's assets for the other postretirement benefits plan (net of participant contributions), respectively, are as follows:

Expected Benefit Payments

Millions of dollars	Pension Benefits	Other Postretirement Benefits
2016	$ 65.1	$ 9.8
2017	63.2	10.5
2018	64.7	11.1
2019	65.3	11.7
2020	65.8	12.3
2021 - 2025	338.3	66.1

Pension Plan Contributions

The pension trust is adequately funded under current regulations. No contributions have been required since 1997, and as a result of closing the plan to new entrants and freezing benefit accruals in the future, SCE&G does not anticipate making significant contributions to the pension plan for the foreseeable future.

Net Periodic Benefit Cost

Consolidated SCE&G records net periodic benefit cost utilizing beginning of the year assumptions. Disclosures required for these plans are set forth in the following tables.

Components of Net Periodic Benefit Cost

	Pension Benefits			Other Postretirement Benefits		
Millions of dollars	2015	2014	2013	2015	2014	2013
Service cost	$ 19.3	$ 16.0	$ 17.6	$ 4.4	$ 3.6	$ 4.6
Interest cost	32.2	34.1	32.6	9.4	9.4	8.7
Expected return on assets	(52.2)	(56.3)	(51.9)	n/a	n/a	n/a
Prior service cost amortization	3.4	3.5	5.0	0.3	0.3	0.6
Amortization of actuarial losses	11.4	4.0	14.3	1.7	—	2.6
Curtailment	—	—	8.4	—	—	—
Net periodic benefit cost	$ 14.1	$ 1.3	$ 26.0	$ 15.8	$ 13.3	$ 16.5

In connection with regulatory orders, SCE&G recovers current pension expense through a rate rider that may be adjusted annually (for retail electric operations) or through cost of service rates (for gas operations). For retail electric operations, current pension expense is recognized based on amounts collected through its rate rider, and differences between actual pension expense and amounts recognized pursuant to the rider are deferred as a regulatory asset (for under-collections) or regulatory liability (for over-collections) as applicable. In addition, SCE&G amortizes certain previously deferred pension costs. See Note 2.

Other changes in plan assets and benefit obligations recognized in OCI (net of tax) were as follows:

	Pension Benefits			Other Postretirement Benefits		
Millions of dollars	2015	2014	2013	2015	2014	2013
Current year actuarial (gain) loss	$ 0.2	$ 0.2	$ (0.8)	$ (0.3)	$ 0.4	$ (0.4)
Amortization of actuarial losses	(0.1)	(0.1)	(0.1)	—	—	(0.1)
Amortization of prior service cost	(0.1)	(0.1)	—	—	—	—
Total recognized in OCI	$ —	$ —	$ (0.9)	$ (0.3)	$ 0.4	$ (0.5)

Other changes in plan assets and benefit obligations recognized in regulatory assets were as follows:

	Pension Benefits			Other Postretirement Benefits		
Millions of dollars	**2015**	**2014**	**2013**	**2015**	**2014**	**2013**
Current year actuarial (gain) loss	$ 12.2	$ 87.7	$ (137.1)	$ (14.0)	$ 15.8	$ (24.4)
Amortization of actuarial losses	(10.4)	(3.5)	(12.7)	(1.5)	—	(2.2)
Amortization of prior service cost	(3.1)	(2.8)	(4.5)	(0.3)	(0.2)	(0.5)
Prior service cost (credit)	—	—	(7.7)	—	—	—
Amortization of transition obligation	—	—	—	—	—	(0.1)
Total recognized in regulatory assets	$ (1.3)	$ 81.4	$ (162.0)	$ (15.8)	$ 15.6	$ (27.2)

Significant Assumptions Used in Determining Net Periodic Benefit Cost

	Pension Benefits			Other Postretirement Benefits		
	2015	**2014**	**2013**	**2015**	**2014**	**2013**
Discount rate	4.20%	5.03%	4.10%/5.07%	4.30%	5.19%	4.19%
Expected return on plan assets	7.50%	8.00%	8.00%	n/a	n/a	n/a
Rate of compensation increase	3.00%	3.00%	3.75%/3.00%	3.00%	3.75%	3.75%
Health care cost trend rate	n/a	n/a	n/a	7.00%	7.40%	7.80%
Ultimate health care cost trend rate	n/a	n/a	n/a	5.00%	5.00%	5.00%
Year achieved	n/a	n/a	n/a	2020	2020	2020

Net periodic benefit cost for the period through September 1, 2013, was determined using a 4.10% discount rate, and net periodic benefit cost after that date was determined using a 5.07% discount rate. Similarly, estimated rates of compensation increase were changed in connection with the September 1, 2013 remeasurement.

The actuarial loss and prior service cost to be amortized from accumulated other comprehensive loss into net periodic benefit cost in 2016 are insignificant.

The estimated amounts to be amortized from regulatory assets into net periodic benefit cost in 2016 are as follows:

Millions of Dollars	**Pension Benefits**	**Other Postretirement Benefits**
Actuarial loss	$ 11.2	$ 0.3
Prior service cost	3.0	0.2
Total	$ 14.2	$ 0.5

Other postretirement benefit costs are subject to annual per capita limits pursuant to the plan's design. As a result, the effect of a one-percent increase or decrease in the assumed health care cost trend rate on total service and interest cost is not significant.

401(k) Retirement Savings Plan

SCE&G participates in a SCANA-sponsored defined contribution plan in which eligible employees may defer up to 75% of eligible earnings subject to certain limits and may diversify their investments. Employee deferrals are fully vested and nonforfeitable at all times. SCE&G provides 100% matching contributions up to 6% of an employee’s eligible earnings. Total matching contributions made to the plan were $21.8 million in 2015, $20.7 million in 2014 and $18.7 million in 2013 and were made in the form of SCANA common stock.

9. SHARE-BASED COMPENSATION

SCE&G participates in the LTECP which provides for grants of nonqualified and incentive stock options, stock appreciation rights, restricted stock, performance shares, performance units and restricted stock units to certain key employees and non-employee directors. The LTECP currently authorizes the issuance of up to five million shares of SCANA’s common stock, no more than one million of which may be granted in the form of restricted stock.

Other changes in plan assets and benefit obligations recognized in regulatory assets were as follows:

	Pension Benefits			Other Postretirement Benefits		
Millions of dollars	**2015**	**2014**	**2013**	**2015**	**2014**	**2013**
Current year actuarial (gain) loss	$ 12.2	$ 87.7	$ (137.1)	$ (14.0)	$ 15.8	$ (24.4)
Amortization of actuarial losses	(10.4)	(3.5)	(12.7)	(1.5)	—	(2.2)
Amortization of prior service cost	(3.1)	(2.8)	(4.5)	(0.3)	(0.2)	(0.5)
Prior service cost (credit)	—	—	(7.7)	—	—	—
Amortization of transition obligation	—	—	—	—	—	(0.1)
Total recognized in regulatory assets	$ (1.3)	$ 81.4	$ (162.0)	$ (15.8)	$ 15.6	$ (27.2)

Significant Assumptions Used in Determining Net Periodic Benefit Cost

	Pension Benefits			Other Postretirement Benefits		
	2015	**2014**	**2013**	**2015**	**2014**	**2013**
Discount rate	4.20%	5.03%	4.10%/5.07%	4.30%	5.19%	4.19%
Expected return on plan assets	7.50%	8.00%	8.00%	n/a	n/a	n/a
Rate of compensation increase	3.00%	3.00%	3.75%/3.00%	3.00%	3.75%	3.75%
Health care cost trend rate	n/a	n/a	n/a	7.00%	7.40%	7.80%
Ultimate health care cost trend rate	n/a	n/a	n/a	5.00%	5.00%	5.00%
Year achieved	n/a	n/a	n/a	2020	2020	2020

Net periodic benefit cost for the period through September 1, 2013, was determined using a 4.10% discount rate, and net periodic benefit cost after that date was determined using a 5.07% discount rate. Similarly, estimated rates of compensation increase were changed in connection with the September 1, 2013 remeasurement.

The actuarial loss and prior service cost to be amortized from accumulated other comprehensive loss into net periodic benefit cost in 2016 are insignificant.

The estimated amounts to be amortized from regulatory assets into net periodic benefit cost in 2016 are as follows:

Millions of Dollars	**Pension Benefits**	**Other Postretirement Benefits**
Actuarial loss	$ 11.2	$ 0.3
Prior service cost	3.0	0.2
Total	$ 14.2	$ 0.5

Other postretirement benefit costs are subject to annual per capita limits pursuant to the plan's design. As a result, the effect of a one-percent increase or decrease in the assumed health care cost trend rate on total service and interest cost is not significant.

401(k) Retirement Savings Plan

SCE&G participates in a SCANA-sponsored defined contribution plan in which eligible employees may defer up to 75% of eligible earnings subject to certain limits and may diversify their investments. Employee deferrals are fully vested and nonforfeitable at all times. SCE&G provides 100% matching contributions up to 6% of an employee’s eligible earnings. Total matching contributions made to the plan were $21.8 million in 2015, $20.7 million in 2014 and $18.7 million in 2013 and were made in the form of SCANA common stock.

9. SHARE-BASED COMPENSATION

SCE&G participates in the LTECP which provides for grants of nonqualified and incentive stock options, stock appreciation rights, restricted stock, performance shares, performance units and restricted stock units to certain key employees and non-employee directors. The LTECP currently authorizes the issuance of up to five million shares of SCANA’s common stock, no more than one million of which may be granted in the form of restricted stock.

Compensation cost is measured based on the grant-date fair value of the instruments issued and is recognized over the period that an employee provides service in exchange for the award. Share-based payment awards do not have non-forfeitable rights to dividends or dividend equivalents. To the extent that the awards themselves do not vest, dividends or dividend equivalents which would have been paid on those awards do not vest.

The 2013-2015 and 2014-2016 performance cycles provide for performance measurement and award determination on an annual basis, with payment of awards being deferred until after the end of the three-year performance cycle. The 2015-2017 award is based on performance over a single three-year cycle. In each performance cycle of the 2013-2015 and 2014-2016 awards, 20% of the performance awards were granted in the form of restricted share units, which are liability awards payable in cash and 80% of the awards were granted in performance shares each of which has a value that is equal to, and changes with, the value of a share of SCANA common stock. For the 2015-2017 awards, 30% are in the form of restricted share units and 70% are in the form of performance shares. Dividend equivalents are accrued on the performance shares and the restricted share units. Performance awards and related dividend equivalents are subject to forfeiture in the event of termination of employment prior to the end of the cycle, subject to certain exceptions. Payouts of performance share awards are determined by SCANA's performance against pre-determined measures of TSR as compared to a peer group of utilities (weighted 50%) and growth in GAAP-adjusted net earnings per share (weighted 50%).

Compensation cost of liability awards is recognized over their respective three-year performance periods based on the estimated fair value of the award, which is periodically updated based on expected ultimate cash payout, and is reduced by estimated forfeitures. Awards under the 2013-2015 performance cycle were paid in cash totaling $3.7 million at SCANA's discretion in February 2016. Cash-settled liabilities related to earlier performance cycles totaled approximately $6.3 million in 2015, $1.9 million in 2014 and $3.2 million in 2013.

Fair value adjustments for all performance cycles resulted in compensation expense recognized in the statements of income totaling approximately $12.2 million in 2015, $12.6 million in 2014 and $5.5 million in 2013. Such fair value adjustments also resulted in capitalized compensation costs of $0.6 million in 2015, $0.6 million in 2014 and $0.5 million in 2013. At December 31, 2015 SCE&G's unrecognized compensation cost was insignificant.

10. COMMITMENTS AND CONTINGENCIES

Nuclear Insurance

Under Price-Anderson, SCE&G (for itself and on behalf of Santee-Cooper, a one-third owner of Summer Station Unit 1) maintains agreements of indemnity with the NRC that, together with private insurance, cover third-party liability arising from any nuclear incident occurring at the company's nuclear power plant. Price-Anderson provides funds up to $13.4 billion for public liability claims that could arise from a single nuclear incident. Each nuclear plant is insured against this liability to a maximum of $375 million by ANI with the remaining coverage provided by a mandatory program of deferred premiums that could be assessed, after a nuclear incident, against all owners of commercial nuclear reactors. Each reactor licensee is currently liable for up to $127.3 million per reactor owned for each nuclear incident occurring at any reactor in the United States, provided that not more than $18.9 million of the liability per reactor would be assessed per year. SCE&G's maximum assessment, based on its two-thirds ownership of Summer Station Unit 1, would be $84.8 million per incident, but not more than $12.6 million per year. Both the maximum assessment per reactor and the maximum yearly assessment are adjusted for inflation at least every five years.

SCE&G currently maintains insurance policies (for itself and on behalf of Santee Cooper) with NEIL. The policies provide coverage to Summer Station Unit 1 for property damage and outage costs up to $2.75 billion resulting from an event of nuclear origin. In addition, a builder's risk insurance policy has been purchased from NEIL for the construction of the New Units. This policy provides the owners of the New Units up to $500 million of coverage for accidental property damage occurring during construction. The NEIL policies, in the aggregate, are subject to a maximum loss of $2.75 billion for any single loss occurrence. All of the NEIL policies permit retrospective assessments under certain conditions to cover insurer's losses. Based on the current annual premiums, SCE&G's portion of the retrospective premium assessment would not exceed $43.5 million.

To the extent that insurable claims for property damage, decontamination, repair and replacement and other costs and expenses arising from a nuclear incident at Summer Station Unit 1 exceed the policy limits of insurance, or to the extent such insurance becomes unavailable in the future, and to the extent that SCE&G rates would not recover the cost of any purchased replacement power, SCE&G will retain the risk of loss as a self-insurer. SCE&G has no reason to anticipate a serious nuclear incident. However, if such an incident were to occur, it likely would have a material impact on the Consolidated SCE&G's results of operations, cash flows and financial position.

New Nuclear Construction

In 2008, SCE&G, on behalf of itself and as agent for Santee Cooper, contracted with the Consortium for the design and construction of the

New Nuclear Construction

In 2008, SCE&G, on behalf of itself and as agent for Santee Cooper, contracted with the Consortium for the design and construction of the New Units at the site of Summer Station. SCE&G's current ownership share in the New Units is 55%. As discussed below, SCE&G has agreed to acquire an additional 5% ownership in the New Units from Santee Cooper.

EPC Contract and BLRA Matters

The construction of the New Units and SCE&G’s related recovery of financing costs through rates is subject to review and approval by the SCPSC as provided for in the BLRA. Under the BLRA, the SCPSC has approved, among other things, a milestone schedule and a capital costs estimates schedule for the New Units. This approval constitutes a final and binding determination that the New Units are used and useful for utility purposes, and that the capital costs associated with the New Units are prudent utility costs and expenses and are properly included in rates, so long as the New Units are constructed or are being constructed within the parameters of the approved milestone schedule, including specified contingencies, and the approved capital costs estimates schedule. Subject to the same conditions, the BLRA provides that SCE&G may apply to the SCPSC annually for an order to recover through revised rates SCE&G’s weighted average cost of capital applied to all or part of the outstanding balance of construction work in progress concerning the New Units. Such annual rate changes are described in Note 2. As of December 31, 2015, SCE&G’s investment in the New Units, including related transmission, totaled $3.6 billion, for which the financing costs on $3.2 billion have been reflected in rates under the BLRA.

The SCPSC granted initial approval of the construction schedule and related forecasted capital costs in 2009. The NRC issued COLs in March 2012. In November 2012, the SCPSC approved an updated milestone schedule and additional updated capital costs for the New Units. In addition, the SCPSC approved revised substantial completion dates for the New Units based on that March 2012 issuance of the COL and the amounts agreed upon by SCE&G and the Consortium in July 2012 to resolve known claims by the Consortium for costs related to COL delays, design modifications of the shield building and certain prefabricated structural modules for the New Units and unanticipated rock conditions at the site. In October 2014, the South Carolina Supreme Court affirmed the SCPSC's order on appeal.

Since the settlement of delay-related claims in 2012, the Consortium has continued to experience delays in the schedule. Shield building construction remains a principal focus area for SCE&G’s oversight of the project. The primary critical path for both Unit 2 and Unit 3 runs through the placement of concrete within the containment vessels, the fabrication of shield building panels, the fabrication of the air inlet and tension rings and the completion of shield building construction. For Unit 3, the critical path also runs through the setting of CA20 which is a prerequisite to concrete placement in certain areas of the nuclear island. Plans to accelerate the work needed to permit placing this concrete are underway. In addition, WEC has reached agreement on a mitigation plan to accelerate shield building panel fabrication with one of its subcontractors. Additional mitigation will be required in critical path areas to support the updated substantial completion dates described below.

During the fourth quarter of 2013, the Consortium began a full re-baselining of the Unit 2 and Unit 3 construction schedules to incorporate a more detailed evaluation of the engineering and procurement activities necessary to accomplish the schedules and to provide a detailed reassessment of the impact of the revised Unit 2 and Unit 3 schedules on engineering and design resource allocations, procurement, construction work crew efficiencies, and other items. The result was a revised fully integrated project schedule with timing of specific construction activities (Revised, Fully-Integrated Construction Schedule) along with related cost information.

The Revised, Fully-Integrated Construction Schedule indicated that the substantial completion of Unit 2 was expected to occur in mid-June 2019 and that the substantial completion of Unit 3 was expected to be approximately 12 months later. The Consortium continues to refine and update the Revised, Fully-Integrated Construction Schedule as designs are finalized, as construction progresses, and as additional information is received.

In September 2015, the SCPSC approved an updated BLRA milestone schedule based on revised substantial completion dates for Units 2 and 3 of June 2019 and June 2020, respectively, each subject to an 18-month contingency period. In addition, the SCPSC approved certain updated owner's costs ($245 million) and other capital costs ($453 million), of which $539 million were associated with the schedule delays and other contested costs. In this proceeding, SCE&G's total projected capital costs (in 2007 dollars) and gross construction cost estimates (including escalation and AFC) were estimated to be $5.2 billion and $6.8 billion, respectively. These projections included cost amounts related to the Revised, Fully-Integrated Construction Schedule for which SCE&G had not accepted responsibility and which were the subject of dispute. As such, these updated milestone schedule and projections did not reflect the resolution of negotiations. In addition, the SCPSC approved a revision to the allowed return on equity for new nuclear construction from 11.0% to 10.5%. This revised return on equity will

be applied prospectively for the purpose of calculating revised rates sought by SCE&G under the BLRA on and after January 1, 2016, until such time as the New Units are completed.

On October 27, 2015, SCE&G, Santee Cooper and the Consortium reached a settlement regarding the above mentioned disputes, and the EPC Contract was amended. The October 2015 Amendment became effective in December 2015, upon the consummation of the acquisition by be applied prospectively for the purpose of calculating revised rates sought by SCE&G under the BLRA on and after January 1, 2016, until such time as the New Units are completed.

On October 27, 2015, SCE&G, Santee Cooper and the Consortium reached a settlement regarding the above mentioned disputes, and the EPC Contract was amended. The October 2015 Amendment became effective in December 2015, upon the consummation of the acquisition by WEC of the stock of Stone & Webster from CB&I. Following that acquisition, Stone & Webster continues to be a member of the Consortium as a subsidiary of WEC rather than CB&I, and WEC has engaged Fluor Corporation as a subcontracted construction manager.

Among other things, the October 2015 Amendment:

(i) resolved by settlement and release substantially all outstanding disputes between SCE&G and the Consortium, in exchange for (a) an additional cost to be paid by SCE&G and Santee Cooper of $300 million (SCE&G’s 55% portion being $165 million) and an increase in the fixed component of the contract price by that amount, and (b) a credit to SCE&G and Santee Cooper of $50 million (SCE&G’s 55% portion being approximately $27 million) to be applied to the target component of the contract price,

(ii) revised the guaranteed substantial completion dates of Units 2 and 3 to August 31, 2019 and 2020, respectively,

(iii) revised the delay-related liquidated damages computation requirements, including those related to the eligibility of the New Units to earn Internal Revenue Code Section 45J production tax credits (see also below), and capped those aggregate liquidated damages at $463 million per New Unit (SCE&G’s 55% portion being approximately $255 million per New Unit),

(iv) provides for payment to the Consortium of a completion bonus of $275 million per New Unit (SCE&G’s 55% portion being approximately $151 million per New Unit) for each New Unit placed in service by the deadline to qualify for production tax credits,

(v) provides for development of a revised construction milestone payment schedule, with SCE&G and Santee Cooper making monthly payments of $100 million (SCE&G’s 55% portion being $55 million) for each of the first five months following effectiveness, followed by payments made based on milestones achieved, and

(vi) provided that SCE&G and Santee Cooper waive and cancel the CB&I parent company guaranty with respect to the project.

Under the October 2015 Amendment, SCE&G’s total estimated project costs increased by approximately $286 million over the $6.8 billion approved by the SCPSC in September 2015, bringing its total estimated gross construction cost of the project (including escalation and AFC) to approximately $7.1 billion.

The payment obligations under the EPC Contract are joint and several obligations of WEC and Stone & Webster, and in connection with the October 2015 Amendment, Toshiba Corporation, WEC’s parent company, reaffirmed its guaranty of WEC’s payment obligations. Based on Toshiba's current credit ratings and pursuant to the terms of the EPC Contract, SCE&G has exercised its rights to demand a payment and performance bond from WEC. Such bond will be based on estimated billings and its aggregate nominal coverage will not exceed $100 million (or $55 million for SCE&G's 55% share). SCE&G and Santee Cooper are responsible for the cost of the bond. In addition, the EPC Contract provides that upon the request of SCE&G, the Consortium must escrow certain intellectual property and software for SCE&G's benefit to enable completion of the New Units. SCE&G has made such a request to the Consortium.

In addition to the above, the October 2015 Amendment provided for an explicit definition of a Change in Law designed to reduce the likelihood of certain future commercial disputes, and the Consortium also acknowledged and agreed that the project scope includes providing New Units that meet the standards of the NRC approved Design Control Document Revision 19. The October 2015 Amendment also established a dispute resolution board process for certain commercial claims and disputes, including any dispute that might arise with respect to the development of the revised construction milestone payment schedule referred to above. The EPC Contract was also revised to eliminate the requirement or ability to bring suit before substantial completion of the project.

Finally, the October 2015 Amendment provides SCE&G and Santee Cooper an irrevocable option, until November 1, 2016 and subject to regulatory approvals, to further amend the EPC Contract to fix the total amount to be paid to the Consortium for its entire scope of work on the project (excluding a limited amount of work within the time and materials component of the contract price) after June 30, 2015 at $6.082 billion (SCE&G’s 55% portion being approximately $3.345 billion). This total amount to be paid would be subject to adjustment for amounts paid since June 30, 2015. Were this fixed price option to be exercised, the aggregate delay-related liquidated damages referred to in (iii) above would be capped at $338

million per unit (SCE&G’s 55% portion being approximately $186 million per unit), and the completion bonus referred to in (iv) above would be $150 million per New Unit (SCE&G’s 55% portion being approximately $83 million per New Unit). The exercise of this fixed price option would result in SCE&G’s total estimated project costs increasing by approximately $774 million over the $6.8 billion approved by the SCPSC in September 2015, and would bring its total estimated gross construction cost (including escalation and AFC) of the project to approximately $7.6 billion.

Resolution of the disputes as described in (i) above, or in the case of the exercise of the fixed price option, would result in estimated million per unit (SCE&G’s 55% portion being approximately $186 million per unit), and the completion bonus referred to in (iv) above would be $150 million per New Unit (SCE&G’s 55% portion being approximately $83 million per New Unit). The exercise of this fixed price option would result in SCE&G’s total estimated project costs increasing by approximately $774 million over the $6.8 billion approved by the SCPSC in September 2015, and would bring its total estimated gross construction cost (including escalation and AFC) of the project to approximately $7.6 billion.

Resolution of the disputes as described in (i) above, or in the case of the exercise of the fixed price option, would result in estimated project costs above the amounts approved by the SCPSC; however, the guaranteed substantial completion dates fall within the SCPSC approved 18-month contingency periods. SCE&G held an allowable ex parte communication briefing with the SCPSC on November 19, 2015 and, following an evaluation as to whether to exercise the fixed price option, expects to file a petition in 2016, as provided under the BLRA, for an update to the project’s estimated capital cost and milestone schedule which would incorporate the impact of the October 2015 Amendment.

Additional claims by the Consortium or SCE&G involving the project schedule and budget may arise as the project continues. The parties to the EPC Contract have established both informal and formal dispute resolution procedures in order to resolve such issues. SCE&G expects to resolve all disputes through both the informal and formal procedures and currently anticipates that any costs that arise through such dispute resolution processes (including those reflected in the October 2015 Amendment described above), as well as other costs identified from time to time, will be recoverable through rates.

Santee Cooper Matters

As noted above, SCE&G has agreed to acquire an additional 5% ownership in the New Units from Santee Cooper. Under the terms of this agreement, SCE&G will acquire a 1% ownership interest in the New Units at the commercial operation date of Unit 2, an additional 2% ownership interest no later than the first anniversary of such commercial operation date, and the final 2% no later than the second anniversary of such commercial operation date. SCE&G has agreed to pay an amount equal to Santee Cooper's actual cost, including its cost of financing, of the percentage conveyed as of the date of each conveyance. In addition, the agreement provides that Santee Cooper will not transfer any of its remaining interest in the New Units to third parties until the New Units are complete. This transaction will not affect the payment obligations between the parties during construction for the New Units, nor is it anticipated that the payments for the additional ownership interest would be reflected in a revised rates filing under the BLRA. Based on the October 2015 Amendment, which has not been approved by the SCPSC, SCE&G’s currently projected cost would be approximately $750 million to $850 million for the additional 5% interest being acquired from Santee Cooper.

Nuclear Production Tax Credits

The IRS has notified SCE&G that, subject to a national megawatt capacity limitation, the electricity to be produced by each of the New Units (advanced nuclear units, as defined) would qualify for nuclear production tax credits under Section 45J of the Internal Revenue Code to the extent that such New Unit is operational before January 1, 2021 and other eligibility requirements are met. These nuclear production tax credits (related to SCE&G's 55% share of both New Units) could total as much as approximately $1.4 billion. Such credits would be earned over the first eight years of each New Unit's operations and would be realized by SCE&G over those years or during allowable carry-forward periods. Based on the guaranteed substantial completion dates provided above, both New Units are expected to be operational and to qualify for the nuclear production tax credits; however, further delays in the schedule or changes in tax law could impact such conclusions. When and to the extent that production tax credits are realized, their benefits are expected to be provided directly to SCE&G's electric customers.

Other Project Matters

When the NRC issued the COLs for the New Units, two of the conditions that it imposed were requiring inspection and testing of certain components of the New Units' passive cooling system, and requiring the development of strategies to respond to extreme natural events resulting in the loss of power at the New Units. In addition, the NRC directed the Office of New Reactors to issue to SCE&G an order requiring enhanced, reliable spent fuel pool instrumentation. SCE&G prepared and submitted an overall integration plan for the New Units to the NRC in August 2013. That plan is currently under review by the NRC and SCE&G does not anticipate any additional regulatory actions as a result of that review, but it cannot predict future regulatory activities or how such initiatives would impact construction or operation of the New Units.

Environmental

Consolidated SCE&G's operations are subject to extensive regulation by various federal and state authorities in the areas of air quality, water quality, control of toxic substances and hazardous and solid wastes. Applicable statutes and

rules include the CAA, CWA, Nuclear Waste Act and CERCLA, among others. In many cases, regulations proposed by such authorities could have a significant impact on Consolidated SCE&G's financial condition, results of operations and cash flows. In addition, Consolidated SCE&G often cannot predict what conditions or requirements will be imposed by regulatory or legislative proposals. To the extent that compliance with environmental regulations or legislation results in capital expenditures or operating costs, Consolidated SCE&G expects to recover such expenditures and costs through existing ratemaking provisions.

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From a regulatory perspective, SCE&G and GENCO continually monitor and evaluate their current and projected emission levels and strive to comply with all state and federal regulations regarding those emissions. SCE&G and GENCO participate in the sulfur dioxide and nitrogen oxide emission allowance programs with respect to coal plant emissions and also have constructed additional pollution control equipment at several larger coal-fired electric generating plants. Further, SCE&G is engaged in construction activities of the New Units which are expected to reduce GHG emission levels significantly once they are completed and dispatched by potentially displacing some of the current coal-fired generation sources. These actions are expected to address many of the rules and regulations discussed herein.

On August 3, 2015, the EPA issued a revised standard for new power plants by re-proposing NSPS under the CAA for emissions of carbon dioxide from newly constructed fossil fuel-fired units. The final rule requires all new coal-fired power plants to meet a carbon emission rate of 1,400 pounds carbon dioxide per MWh and new natural gas units to meet 1,000 pounds carbon dioxide per MWh. While most new natural gas plants will not be required to include any new technologies, no new coal-fired plants could be constructed without partial carbon capture and sequestration capabilities. Consolidated SCE&G is evaluating the final rule, but does not plan to construct new coal-fired units in the foreseeable future.

In addition, on August 3, 2015, the EPA issued its final rule on emission guidelines for states to follow in developing plans to address GHG emissions from existing units. The rule includes state-specific goals for reducing national carbon dioxide emissions by 32% from 2005 levels by 2030. The rule also provides for nuclear reactors under construction, such as the New Units, to count towards compliance and establishes a phased-in compliance approach beginning in 2022. The rule gives states from one to three years to issue SIPs, which will ultimately define the specific compliance methodology that will be applied to existing units in that state. It is expected that South Carolina will request a two-year extension (until September 2018). On February 9, 2016, the Supreme Court stayed the rule pending disposition of a petition of review of the rule in the Court of Appeals. The order of the Supreme Court has no immediate impact on SCE&G and GENCO or their generation operations. Consolidated SCE&G is currently evaluating the rule and expects any costs incurred to comply with such rule to be recoverable through rates.

In July 2011, the EPA issued the CSAPR to reduce emissions of sulfur dioxide and nitrogen oxide from power plants in the eastern half of the United States. A series of court actions stayed this rule until October 23, 2014, when the Court of Appeals granted a motion to lift the stay. On December 3, 2014, the EPA published an interim final rule that aligns the dates in the CSAPR text with the revised court-ordered schedule, which delayed the implementation dates to 2015 for Phase 1 and to 2017 for Phase 2. The CSAPR replaces the CAIR and requires a total of 28 states to reduce annual sulfur dioxide emissions and annual or ozone season nitrogen oxide emissions to assist in attaining the ozone and fine particle NAAQS. The rule establishes an emissions cap for sulfur dioxide and nitrogen oxide and limits the trading for emission allowances by separating affected states into two groups with no trading between the groups. On July 28, 2015, the Court of Appeals held that Phase 2 emissions budgets for certain states, including South Carolina, required reductions in emissions beyond the point necessary to achieve downwind attainment and were, therefore, invalid. The Court of Appeals remanded CSAPR, without vacating the rule, to the EPA for further consideration. The opinion of the Court of Appeals has no immediate impact on SCE&G and GENCO or their generation operations. Air quality control installations that SCE&G and GENCO have already completed have positioned them to comply with the existing allowances set by the CSAPR. Any cost incurred to comply with CSAPR are expected to be recoverable through rates.

In April 2012, the EPA's MATS rule containing new standards for mercury and other specified air pollutants became effective. The rule provides up to four years for generating facilities to meet the standards, and SCE&G and GENCO's evaluation of the rule is ongoing. SCE&G's decision to retire certain coal-fired units (see Note 2) and its project to build the New Units along with other actions are expected to result in the SCE&G's compliance with MATS.

On November 19, 2014, the EPA finalized its reconsideration of certain provisions applicable during startup and shutdown of generating facilities under the MATS rule. SCE&G and GENCO have received a one year extension (until April 2016) to comply with MATS at Cope, McMeekin, Wateree and Williams Stations. These extensions will allow time to convert McMeekin Station to burn natural gas and to install additional pollution control devices at the other plants that will enhance the control of certain MATS-regulated pollutants. On June 29, 2015, the U.S. Supreme Court ruled that the EPA unreasonably failed to consider costs in its decision to regulate, and remanded a case challenging the regulation on that basis to the Court of

Appeals. The Court noted during remand that EPA has said that it is on track to issue a revised "appropriate and necessary" finding by April 15, 2016. The ruling, however, is not expected to have an impact on SCE&G or GENCO due to the aforementioned retirements and conversions. SCE&G and GENCO currently are in compliance with the MATS rule and expect to remain in compliance.

The CWA provides for the imposition of effluent limitations that require treatment for wastewater discharges. Under the CWA, compliance with applicable limitations is achieved under state-issued NPDES permits. As a facility's NPDES permit is renewed (every five years), Appeals. The Court noted during remand that EPA has said that it is on track to issue a revised "appropriate and necessary" finding by April 15, 2016. The ruling, however, is not expected to have an impact on SCE&G or GENCO due to the aforementioned retirements and conversions. SCE&G and GENCO currently are in compliance with the MATS rule and expect to remain in compliance.

The CWA provides for the imposition of effluent limitations that require treatment for wastewater discharges. Under the CWA, compliance with applicable limitations is achieved under state-issued NPDES permits. As a facility's NPDES permit is renewed (every five years), any new effluent limitations would be incorporated. The ELG Rule became effective on January 4, 2016. After this date, state regulators will modify facility NPDES permits to match more restrictive standards, thus requiring facilities to retrofit with new wastewater treatment technologies. Compliance dates will vary by type of wastewater, and some will be based on a facility's five year permit cycle and thus may range from 2018 to 2023. Consolidated SCE&G expects that wastewater treatment technology retrofits will be required at Williams and Wateree Stations and may be required at other facilities. Any costs incurred to comply with the ELG Rule are expected to be recoverable through rates.

The CWA Section 316(b) Existing Facilities Rule became effective in October 2014. This rule establishes national requirements for the location, design, construction and capacity of cooling water intake structures at existing facilities that reflect the best technology available for minimizing the adverse environmental impacts of impingement and entrainment. SCE&G and GENCO are conducting studies and implementing plans to ensure compliance with this rule. In addition, Congress is expected to consider further amendments to the CWA. Such legislation may include toxicity-based standards as well as limitations to mixing zones.

On April 17, 2015, the EPA's final rule for CCR was published in the Federal Register and became effective in the fourth quarter of 2015. This rule regulates CCR as a non-hazardous waste under Subtitle D of the Resource Conservation and Recovery Act and imposes certain requirements on ash storage ponds and other CCR management facilities at SCE&G's and GENCO's coal-fired generating facilities. Although the full effects of this rule are still being evaluated, SCE&G and GENCO have already closed or have begun the process of closure of all of their ash storage ponds and have previously recognized AROs for such ash storage ponds under existing requirements. Consolidated SCE&G does not expect the incremental compliance costs associated with this rule to be significant and expects to recover such costs in future rates.

The Nuclear Waste Act required that the United States government accept and permanently dispose of high-level radioactive waste and spent nuclear fuel by January 31, 1998, and it imposed on utilities the primary responsibility for storage of their spent nuclear fuel until the repository is available. SCE&G entered into a Standard Contract for Disposal of Spent Nuclear Fuel and/or High-Level Radioactive Waste with the DOE in 1983. As of December 31, 2015, the federal government has not accepted any spent fuel from Summer Station Unit 1, and it remains unclear when the repository may become available. SCE&G has on-site spent nuclear fuel storage capability in its existing fuel pool until at least 2017 and has constructed a dry cask storage facility to accommodate the spent nuclear fuel output for the life of Summer Station Unit 1. SCE&G may evaluate other technology as it becomes available.

The provisions of CERCLA authorize the EPA to require the clean-up of hazardous waste sites. The state of South Carolina has similar laws. SCE&G maintains an environmental assessment program to identify and evaluate current and former operations sites that could require clean-up. In addition, regulators from the EPA and other federal or state agencies periodically notify SCE&G that it may be required to perform or participate in the investigation and remediation of a hazardous waste site. As site assessments are initiated, estimates are made of the amount of expenditures, if any, deemed necessary to investigate and remediate each site. These estimates are refined as additional information becomes available; therefore, actual expenditures may differ significantly from the original estimates. Amounts estimated and accrued to date for site assessments and clean-up relate solely to regulated operations. Such amounts are recorded in regulatory assets and amortized, with recovery provided through rates.

SCE&G is responsible for four decommissioned MGP sites in South Carolina which contain residues of by-product chemicals. These sites are in various stages of investigation, remediation and monitoring under work plans approved by DHEC and the EPA. SCE&G anticipates that major remediation activities at all these sites will continue until at least through 2017 and will cost an additional $18.5 million, which is accrued in Other within Deferred Credits and Other Liabilities on the consolidated balance sheet. SCE&G expects to recover any cost arising from the remediation of MGP sites through rates. At December 31, 2015, deferred amounts, net of amounts previously recovered through rates and insurance settlements, totaled $34.8 million and are included in regulatory assets.

Claims and Litigation

Consolidated SCE&G is subject to various claims and litigation incidental to its business operations which management anticipates will be resolved without a material impact on Consolidated SCE&G's results of operations, cash flows or financial condition.

Operating Lease Commitments

Consolidated SCE&G is obligated under various operating leases for rail cars, vehicles, office space, furniture and equipment. Leases expire at various dates through 2051. Rent expense totaled approximately $12.3 million in 2015, $12.1 million in 2014 and $13.6 million in 2013.

Claims and Litigation

Consolidated SCE&G is subject to various claims and litigation incidental to its business operations which management anticipates will be resolved without a material impact on Consolidated SCE&G’s results of operations, cash flows or financial condition.

Operating Lease Commitments

Consolidated SCE&G is obligated under various operating leases for rail cars, vehicles, office space, furniture and equipment. Leases expire at various dates through 2051. Rent expense totaled approximately $12.3 million in 2015, $12.1 million in 2014 and $13.6 million in 2013. Future minimum rental payments under such leases will be $4 million in 2016, $2 million in 2017, $1 million in 2018, $1 million in 2019, $1 million in 2020 and $17 million thereafter.

Asset Retirement Obligations

Consolidated SCE&G recognizes a liability for the present value of an ARO when incurred if the liability can be reasonably estimated. Uncertainty about the timing or method of settlement of a conditional ARO is factored into the measurement of the liability when sufficient information exists, but such uncertainty is not a basis upon which to avoid liability recognition.

The legal obligations associated with the retirement of long-lived tangible assets that result from their acquisition, construction, development and normal operation relate primarily to Consolidated SCE&G’s regulated utility operations. As of December 31, 2015, Consolidated SCE&G has recorded AROs of approximately $176 million for nuclear plant decommissioning (see Note 1) and AROs of approximately $312 million for other conditional obligations primarily related to generation, transmission and distribution properties, including gas pipelines. All of the amounts recorded are based upon estimates which are subject to varying degrees of imprecision, particularly since such payments will be made many years in the future.

A reconciliation of the beginning and ending aggregate carrying amount of AROs is as follows:

Millions of dollars	**2015**	**2014**
Beginning balance	$ 536	$ 547
Liabilities incurred	—	3
Liabilities settled	(16)	(6)
Accretion expense	23	25
Revisions in estimated cash flows	(55)	(33)
Ending Balance	$ 488	$ 536

In 2015, revisions in estimated cash flows primarily relate to changes in the expected timing of ARO settlements due to changes in the estimated useful lives of certain electric utility properties identified as part of a customary depreciation study. In 2014 such revisions primarily relate to lower estimates for certain environmental clean up obligations at generation facilities.

11. AFFILIATED TRANSACTIONS

Prior to January 31, 2015, CGT was a wholly-owned subsidiary of SCANA and transported natural gas to SCE&G to serve retail gas customers and certain electric generation requirements. SCE&G's purchases from CGT totaled approximately $3.4 million in 2015, $30.0 million in 2014 and $33.3 million in 2013. SCE&G's payables to CGT for transportation services were $3.3 million at December 31, 2014, and SCE&G's receivables from CGT related to such transportation services were $1.2 million at December 31, 2014.

SCE&G purchases natural gas and related pipeline capacity from SEMI to serve its retail gas customers and certain electric generation requirements. Such purchases totaled approximately $128.5 million in 2015, $195.7 million in 2014 and $166.9 million in 2013. SCE&G’s payables to SEMI for such purchases were $7.5 million and $12.6 million as of December 31, 2015 and 2014, respectively.

SCE&G owns 40% of Canadys Refined Coal, LLC which is involved in the manufacturing and sale of refined coal to reduce emissions. SCE&G accounts for this investment using the equity method. SCE&G’s total purchases from this affiliate were $233.2 million in 2015, $260.3 million in 2014 and $134.2 million in 2013. SCE&G’s total sales to this affiliate were

$232.0 million in 2015, $259.0 million in 2014 and $133.6 million in 2013. SCE&G’s payable to this affiliate was $12.9 million at December 31, 2015 and $27.9 million at December 31, 2014 SCE&G’s receivable from this affiliate was $12.8 million at December 31, 2015 and $27.8 million at

$232.0 million in 2015, $259.0 million in 2014 and $133.6 million in 2013. SCE&G’s payable to this affiliate was $12.9 million at December 31, 2015 and $27.9 million at December 31, 2014 SCE&G’s receivable from this affiliate was $12.8 million at December 31, 2015 and $27.8 million at December 31, 2014.

SCANA Services, for itself and its parent company, provides the following services to Consolidated SCE&G, which are rendered at direct or allocated cost: information systems services, telecommunications services, customer services, marketing and sales, human resources, corporate compliance, purchasing, financial services, risk management, public affairs, legal services, investor relations, gas supply and capacity management, strategic planning, general administrative services and retirement benefits. In addition, SCANA Services processes and pays invoices for Consolidated SCE&G and is reimbursed. Costs for these services totaled $300.0 million in 2015, $292.2 million in 2014 and $285.6 million in 2013. Consolidated SCE&G's payables to SCANA Services for these services were $57.0 million and $47.3 million at December 31, 2015 and 2014, respectively.

Borrowings from and investments in an affiliated money pool are described in Note 4. SCE&G's participation in SCANA's noncontributory defined benefit pension plan and unfunded postretirement health care and life insurance programs are described in Note 8.

12. SEGMENT OF BUSINESS INFORMATION

Consolidated SCE&G’s reportable segments follow the same accounting policies as those described in Note 1 and reflect the effect of certain reclassifications described therein.

Electric Operations primarily generates, transmits, and distributes electricity, and is regulated by the SCPSC and FERC. Gas Distribution purchases and sells natural gas, primarily at retail, and is regulated by the SCPSC.

Management uses operating income to measure segment profitability for regulated operations and evaluates utility plant, net, for its segments. As a result, Consolidated SCE&G does not allocate interest charges, income tax expense, earnings available to common shareholder or assets other than utility plant to its segments. Intersegment revenue and interest income were not significant. Consolidated SCE&G’s deferred tax assets are netted with deferred tax liabilities for reporting purposes.

The consolidated financial statements report operating revenues which are comprised of the reportable segments. Revenues from non-reportable segments are included in Other Income. Segment Assets include utility plant, net for all reportable segments. As a result, adjustments to assets include non-utility plant and non-fixed assets for the segments. Adjustments to Interest Expense and Deferred Tax Assets include amounts that are not allocated to the segments. Expenditures for Assets are adjusted for revisions to estimated cash flows related to AROs, and totals not allocated to other segments.

Disclosure of Reportable Segments (Millions of dollars)

	Electric Operations	Gas Distribution	Adjustments/ Eliminations	Consolidated Total
2015				
External Revenue	$ 2,557	$ 373	—	$ 2,930
Operating Income	876	58	—	934
Interest Expense	17	—	$ 231	248
Depreciation and Amortization	277	28	(11)	294
Segment Assets	10,883	757	3,125	14,765
Expenditures for Assets	1,087	57	(136)	1,008
Deferred Tax Assets	5	n/a	(5)	—
2014				
External Revenue	$ 2,629	$ 462	—	$ 3,091
Operating Income	768	62	—	830
Interest Expense	19	—	$ 209	228
Depreciation and Amortization	300	27	(12)	315
Segment Assets	10,182	721	3,175	14,078

Disclosure of Reportable Segments (Millions of dollars)

	Electric Operations	Gas Distribution	Adjustments/ Eliminations	Consolidated Total
2015				
External Revenue	$ 2,557	$ 373	—	$ 2,930
Operating Income	876	58	—	934
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Depreciation and Amortization	277	28	(11)	294
Segment Assets	10,883	757	3,125	14,765
Expenditures for Assets	1,087	57	(136)	1,008
Deferred Tax Assets	5	n/a	(5)	—
2014				
External Revenue	$ 2,629	$ 462	—	$ 3,091
Operating Income	768	62	—	830
Interest Expense	19	—	$ 209	228
Depreciation and Amortization	300	27	(12)	315
Segment Assets	10,182	721	3,175	14,078
Expenditures for Assets	936	55	(57)	934
Deferred Tax Assets	11	n/a	(11)	—
2013				
External Revenue	$ 2,431	$ 414	—	$ 2,845
Operating Income	679	58	—	737
Interest Expense	19	—	$ 198	217
Depreciation and Amortization	294	26	(7)	313
Segment Assets	9,488	686	2,499	12,673
Expenditures for Assets	907	45	51	1,003
Deferred Tax Assets	10	n/a	(10)	—

13. QUARTERLY FINANCIAL DATA (UNAUDITED)

Millions of dollars	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Annual
2015					
Total operating revenues	$ 772	$ 709	$ 806	$ 643	$ 2,930
Operating income	237	218	307	172	934
Net Income	126	111	167	76	480
Earnings Available to Common Shareholder	122	107	164	73	466
2014					
Total operating revenues	$ 859	$ 698	$ 812	$ 722	$ 3,091
Operating income	239	145	272	174	830
Net Income	126	99	157	76	458
Earnings Available to Common Shareholder	123	96	154	73	446

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

Not Applicable.

ITEM 9A. CONTROLS AND PROCEDURES

SCANA:

Evaluation of Disclosure Controls and Procedures:

As of December 31, 2015, SCANA conducted an evaluation under the supervision and with the participation of its management, including its CEO and CFO, of the effectiveness of the design and operation of SCANA’s disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934). Based on this evaluation, the CEO and CFO concluded that, as of December 31, 2015, SCANA's disclosure controls and procedures were effective.

Management’s Evaluation of Internal Control Over Financial Reporting:

As of December 31, 2015, SCANA conducted an evaluation under the supervision and with the participation of its management, including its CEO and CFO, of any change in SCANA's internal controls over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) of the Securities Exchange Act of 1934) during the quarter ended December 31, 2015. There has been no change in SCANA’s internal controls over financial reporting during the quarter ended December 31, 2015 that has materially affected or is reasonably likely to materially affect SCANA’s internal control over financial reporting.

The Management Report on Internal Control over Financial Reporting follows.

MANAGEMENT REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of SCANA is responsible for establishing and maintaining adequate internal control over financial reporting. SCANA’s internal control system was designed by or under the supervision of SCANA’s management, including its CEO and CFO, to provide reasonable assurance to SCANA’s management and board of directors regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Also, the effectiveness of the internal control over financial reporting may deteriorate in future periods due to either changes in conditions or declining levels of compliance with policies or procedures.

SCANA’s management assessed the effectiveness of SCANA’s internal control over financial reporting as of December 31, 2015. In making this assessment, SCANA used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control—Integrated Framework (2013)*. Based on this assessment, SCANA’s management believes that, as of December 31, 2015, internal control over financial reporting is effective based on those criteria.

SCANA’s independent registered public accounting firm has issued an attestation report on SCANA’s internal control over financial reporting. This report follows.

ATTESTATION REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM ON INTERNAL CONTROL OVER FINANCIAL REPORTING

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
SCANA Corporation
Cayce, South Carolina

We have audited the internal control over financial reporting of SCANA Corporation and subsidiaries (the "Company") as of December 31, 2015, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management Report on Internal Control

ATTESTATION REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM ON INTERNAL CONTROL OVER FINANCIAL REPORTING

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
SCANA Corporation
Cayce, South Carolina

We have audited the internal control over financial reporting of SCANA Corporation and subsidiaries (the "Company") as of December 31, 2015, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2015, based on the criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements and financial statement schedule as of and for the year ended December 31, 2015, of the Company and our report dated February 26, 2016, expressed an unqualified opinion on those financial statements and financial statement schedule.

/s/DELOITTE & TOUCHE LLP
Charlotte, North Carolina
February 26, 2016

SCE&G:

Evaluation of Disclosure Controls and Procedures:

As of December 31, 2015, SCE&G conducted an evaluation under the supervision and with the participation of its management, including its CEO and CFO, of the effectiveness of the design and operation of SCE&G’s disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934). Based on this evaluation, the CEO and CFO concluded that, as of December 31, 2015, SCE&G's disclosure controls and procedures were effective.

SCE&G:

Evaluation of Disclosure Controls and Procedures:

As of December 31, 2015, SCE&G conducted an evaluation under the supervision and with the participation of its management, including its CEO and CFO, of the effectiveness of the design and operation of SCE&G's disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934). Based on this evaluation, the CEO and CFO concluded that, as of December 31, 2015, SCE&G's disclosure controls and procedures were effective.

Management's Evaluation of Internal Control Over Financial Reporting:

As of December 31, 2015, SCE&G conducted an evaluation under the supervision and with the participation of its management, including its CEO and CFO, of any change in SCE&G's internal controls over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) of the Securities Exchange Act of 1934) during the quarter ended December 31, 2015. There has been no change in SCE&G's internal controls over financial reporting during the quarter ended December 31, 2015 that has materially affected or is reasonably likely to materially affect SCE&G's internal control over financial reporting.

The Management Report on Internal Control over Financial Reporting follows.

MANAGEMENT REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of SCE&G is responsible for establishing and maintaining adequate internal control over financial reporting. SCE&G's internal control system was designed by or under the supervision of SCE&G's management, including its CEO and CFO, to provide reasonable assurance to SCE&G's management and board of directors regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Also, the effectiveness of the internal control over financial reporting may deteriorate in future periods due to either changes in conditions or declining levels of compliance with policies or procedures.

SCE&G's management assessed the effectiveness of SCE&G's internal control over financial reporting as of December 31, 2015. In making this assessment, SCE&G used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control-Integrated Framework (2013)*. Based on this assessment, SCE&G's management believes that, as of December 31, 2015, internal control over financial reporting is effective based on those criteria.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

SCANA: A list of SCANA's executive officers is in Part I of this annual report at page 23. The other information required by ITEM 10 is incorporated herein by reference to the captions "INFORMATION ABOUT EXPERIENCE AND QUALIFICATION OF DIRECTORS AND NOMINEES," "NOMINEES FOR DIRECTORS," "CONTINUING DIRECTORS," "BOARD MEETINGS-COMMITTEES OF THE BOARD", "GOVERNANCE INFORMATION-SCANA's Code of Conduct & Ethics" and "OTHER INFORMATION-Section 16(a) Beneficial Ownership Reporting Compliance" in SCANA's definitive proxy statement for the 2016 annual meeting of shareholders which will be filed with the SEC pursuant to Regulation 14A, promulgated under the Securities Exchange Act of 1934 within 120 days after the end of SCANA's fiscal year.

SCE&G: Not applicable.

ITEM 11. EXECUTIVE COMPENSATION

SCANA: The information required by ITEM 11 is incorporated herein by reference to the captions "Compensation Committee Interlocks and Insider Participation," "Compensation Discussion and Analysis," Compensation Committee Report," "Summary Compensation Table," "2015 Grants of Plan-Based Awards," "Outstanding Equity Awards at 2015 Fiscal Year-End," "2015 Option Exercises and Stock Vested," "Pension Benefits," "2015 Nonqualified Deferred Compensation," and "Potential Payments Upon Termination or Change in Control," under the heading "EXECUTIVE COMPENSATION" and the heading "DIRECTOR COMPENSATION" in SCANA's definitive proxy statement for the 2016 annual meeting of shareholders which will be filed with the SEC pursuant to Regulation 14A, promulgated under the Securities Exchange Act of 1934 within 120 days after the end of SCANA's fiscal year.

PART III

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SCE&G: Not applicable.

ITEM 11. EXECUTIVE COMPENSATION

SCANA: The information required by ITEM 11 is incorporated herein by reference to the captions "Compensation Committee Interlocks and Insider Participation," "Compensation Discussion and Analysis," Compensation Committee Report," "Summary Compensation Table," "2015 Grants of Plan-Based Awards," "Outstanding Equity Awards at 2015 Fiscal Year-End," "2015 Option Exercises and Stock Vested," "Pension Benefits," "2015 Nonqualified Deferred Compensation," and "Potential Payments Upon Termination or Change in Control," under the heading "EXECUTIVE COMPENSATION" and the heading "DIRECTOR COMPENSATION" in SCANA's definitive proxy statement for the 2016 annual meeting of shareholders which will be filed with the SEC pursuant to Regulation 14A, promulgated under the Securities Exchange Act of 1934 within 120 days after the end of SCANA's fiscal year.

SCE&G: Not applicable.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

SCANA: Information required by ITEM 12 is incorporated herein by reference to the caption "SHARE OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT" in SCANA's definitive proxy statement for the 2016 annual meeting of shareholders which will be filed with the SEC pursuant to Regulation 14A, promulgated under the Securities Exchange Act of 1934 within 120 days after the end of SCANA's fiscal year.

Equity securities issuable under SCANA's compensation plans at December 31, 2015 are summarized as follows:

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights	Weighted-average exercise price of outstanding options, warrants and rights	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
	(a)	(b)	(c)
Equity compensation plans approved by security holders:			
2015 Long-Term Equity Compensation Plan	157,316 (1)	n/a	4,842,684
Prior Long-Term Equity Compensation Plan	493,611 (2)	n/a	—
Non-Employee Director Compensation Plan	n/a	n/a	49,913
Equity compensation plans not approved by security holders	n/a	n/a	n/a
Total	650,927	n/a	4,892,597

(1) Represents unearned non-vested performance share awards from the 2015-2017 performance period assuming a target level payout.
(2) Represents earned non-vested performance share awards from the 2014-2016 performance period at achieved levels and unearned non-vested performance share awards from the 2014-2016 performance period assuming a target level payout. Also includes 226,902 performance shares related to vested grants from the 2013-2015 performance period which were settled in cash rather than shares in February 2016. The remaining award amount of 266,709 will be 128,132 higher if maximum level payout is earned for the 2014-2016 performance period.

SCE&G: Not applicable.

SCE&G: Not applicable.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

SCANA: The information required by ITEM 13 is incorporated herein by reference to the captions "RELATED PARTY TRANSACTIONS" and "GOVERNANCE INFORMATION - Director Independence" in SCANA's definitive proxy statement for the 2016 annual meeting of shareholders which will be filed with the SEC pursuant to Regulation 14A, promulgated under the Securities Exchange Act of 1934 within 120 days after the end of SCANA's fiscal year.

SCE&G: Not applicable.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

SCANA: The information required by ITEM 14 is incorporated herein by reference to "PROPOSAL 2-APPROVAL OF THE APPOINTMENT OF THE INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM" in SCANA's definitive proxy statement for the 2016 annual meeting of shareholders which will be filed with the SEC pursuant to Regulation 14A, promulgated under the Securities and Exchange Act of 1934 within 120 days after the end of SCANA's fiscal year.

SCE&G: The Audit Committee Charter requires the Audit Committee to pre-approve all auditing services and permitted non-audit services (including the fees and terms thereof) to be performed by the independent registered accounting firm. Pursuant to a policy adopted by the Audit Committee, its Chairman may pre-approve the rendering of services on behalf of the Audit Committee. Decisions by the Chairman to pre-approve the rendering of services are presented to the Audit Committee at its next scheduled meeting.

Independent Registered Public Accounting Firm's Fees

The following table sets forth the aggregate fees, all of which were approved by the Audit Committee, charged to SCE&G and its consolidated affiliates for the fiscal years ended December 31, 2015 and 2014 by Deloitte & Touche LLP, the member firms of Deloitte Touche Tohmatsu, and their respective affiliates.

	2015	2014
Audit Fees (1)	$ 2,032,222	$ 1,977,658
Audit-Related Fees (2)	114,832	123,107
Total Fees	$ 2,147,054	$ 2,100,765

(1) Fees for audit services billed in 2015 and 2014 consisted of audits of annual financial statements, comfort letters, statutory and regulatory audits, consents and other services related to SEC filings, and accounting research.

(2) Fees primarily for employee benefit plan audits.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) The following documents are filed or furnished as a part of this Form 10-K:

(1) Financial Statements and Schedules:

The Report of Independent Registered Public Accounting Firm on the financial statements for each of SCANA and SCE&G is listed under ITEM 8 herein.

The financial statements and supplementary financial data filed as part of this report for SCANA and SCE&G are listed under ITEM 8 herein.

The financial statement schedules "Schedule II - Valuation and Qualifying Accounts" filed as part of this report for SCANA and SCE&G are included below.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) The following documents are filed or furnished as a part of this Form 10-K:

(1) Financial Statements and Schedules:

The Report of Independent Registered Public Accounting Firm on the financial statements for each of SCANA and SCE&G is listed under ITEM 8 herein.

The financial statements and supplementary financial data filed as part of this report for SCANA and SCE&G are listed under ITEM 8 herein.

The financial statement schedules "Schedule II - Valuation and Qualifying Accounts" filed as part of this report for SCANA and SCE&G are included below.

(2) Exhibits

Exhibits required to be filed or furnished with this Annual Report on Form 10-K are listed in the Exhibit Index following the signature page. Certain of such exhibits which have heretofore been filed with the SEC and which are designated by reference to their exhibit number in prior filings are incorporated herein by reference and made a part hereof.

Pursuant to Rule 15d-21 promulgated under the Securities Exchange Act of 1934, the annual report for SCANA’s employee stock purchase plan will be furnished under cover of Form 11-K to the SEC when the information becomes available.

As permitted under Item 601(b)(4)(iii) of Regulation S-K, instruments defining the rights of holders of long-term debt of less than 10% of the total consolidated assets of SCANA, for itself and its subsidiaries and of SCE&G, for itself and its consolidated affiliates, have been omitted and SCANA and SCE&G agree to furnish a copy of such instruments to the SEC upon request.

Schedule II—Valuation and Qualifying Accounts
(in millions)

Description		Beginning Balance	Additions: Charged to Income	Additions: Charged to Other Accounts	Deductions from Reserves	Ending Balance
SCANA:						
Reserves deducted from related assets on the balance sheet:						
Uncollectible accounts						
	2015	$ 7	$ 12	—	$ 14	$ 5
	2014	6	16	—	15	7
	2013	7	13	—	14	6
Reserves other than those deducted from assets on the balance sheet:						
Reserve for injuries and damages						
	2015	$ 5	$ 11	—	$ 10	$ 6
	2014	6	7	—	8	5
	2013	6	4	—	4	6
SCE&G:						
Reserves deducted from related assets on the balance sheet:						
Uncollectible accounts						

Schedule II—Valuation and Qualifying Accounts
(in millions)

			Additions			
Description		**Beginning Balance**	**Charged to Income**	**Charged to Other Accounts**	**Deductions from Reserves**	**Ending Balance**
SCANA:						
Reserves deducted from related assets on the balance sheet:						
Uncollectible accounts						
	2015	$ 7	$ 12	—	$ 14	$ 5
	2014	6	16	—	15	7
	2013	7	13	—	14	6
Reserves other than those deducted from assets on the balance sheet:						
Reserve for injuries and damages						
	2015	$ 5	$ 11	—	$ 10	$ 6
	2014	6	7	—	8	5
	2013	6	4	—	4	6
SCE&G:						
Reserves deducted from related assets on the balance sheet:						
Uncollectible accounts						
	2015	$ 4	$ 6	—	$ 7	$ 3
	2014	3	8	—	7	4
	2013	3	7	—	7	3
Reserves other than those deducted from assets on the balance sheet:						
Reserve for injuries and damages						
	2015	$ 3	$ 11	—	$ 9	$ 5
	2014	5	1	—	3	3
	2013	5	3	—	3	5

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

SCANA CORPORATION

BY: /s/ K. B. Marsh

K. B. Marsh, Chairman of the Board, President, Chief Executive Officer, Chief Operating Officer and Director

DATE: February 26, 2016

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signatures of the undersigned shall be deemed to relate only to matters having